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Government of the Province of Alberta

OIL AND GAS
CONSERVATION BOARD

Report to

THE LIEUTENANT GOVERNOR IN COUNCIL

With Respect to the Applications under The Gas Resources Preservation Act, 1956, of:

Alberta and Southern Gas Co. Ltd.
Westcoast Transmission Company Limited

September, 1958

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INTRODUCTION

THE APPLICATIONS OF ALBERTA AND SOUTHERN GAS CO. LTD. AND WESTCOAST TRANSMISSION COMPANY LIMITED

Applications under The Gas Resources Preservation Act, 1956, by Alberta and Southern Gas Co. Ltd. (herein called "Alberta and Southern") and Westcoast Transmission Company Limited (herein called "Westcoast") now before this Board have so many parallel features with regard to area of supply, markets, provision for Alberta requirements and other matters, that they necessarily must be considered together.

The Board sat on the Westcoast hearing on December 10th to 13th, 16th and 17th, 1957, January 13th and 28th, 1958, and (following the first Calgary sitting of the Royal Commission on Energy) March 4th to 7th.

The hearing of the Alberta and Southern application, having been advertised for that date, opened on February 11th, 1958, and was adjourned until after the sitting of the Royal Commission and the conclusion of the Westcoast hearing. Upon resumption, the hearing ran from March 11th to March 31st.

WESTCOAST APPLICATION

Westcoast seeks a permit to acquire and remove from the Province over a period of 25 years a total of 1.3 trillion cubic feet of gas at the maximum rates of 55 billion cubic feet per year and 170 million cubic feet per day. It proposes to take the gas from two sour gas fields (Savanna Creek and Calgary) for which it has purchase contracts. Some 3.5 billion of the 1.3 trillion cubic feet of gas is to be distributed to communities in Alberta and south-east British Columbia and the balance is to be delivered at the international boundary near Kingsgate to the Pacific Northwest Pipeline Corporation which owns and operates a gas pipe line in the States of Washington, Oregon, Idaho, Wyoming, Utah, Colorado and New Mexico.

The applicant proposes to construct 43 miles of 23-inch pipe line and 29.5 miles of 16-inch gathering system to deliver sour gas from the Savanna Creek field to a gas processing plant to be located in the vicinity of Coleman. Sour gas from the Calgary field will be processed at a plant near Calgary. Residue gas from the Calgary and Coleman plants will be transported through facilities to be constructed by The Alberta Gas Trunk Line Company Limited to a point near the Alberta-British Columbia boundary in the Crowsnest Pass and from there, through a 30-inch pipe line to be constructed by Westcoast, a distance of 105.7 miles to a point near Kingsgate, British Columbia.

Westcoast stated during the hearing that, if required to meet Alberta requirements, it would construct a sour gas gathering system connecting the Wimborne, Harmattan-Elkton, Sundre and Westward Ho Fields to a processing plant to be constructed south of Calgary, or, alternatively, a gathering system to take gas from the Wimborne Field alone to a processing plant at Calgary. The applicant said that it made arrangements with Pacific Northwest Pipeline Corporation to take gas from the aforesaid fields surplus to the Alberta requirements (up to 200 million cubic feet per day), which would enable production from the fields to be taken in suitable annual volumes and at uniform daily rates to permit the economical gathering and processing of the gas.

Westcoast was incorporated by an Act of Parliament in 1949 and with a subsidiary, Westcoast Transmission Company (Alberta) Ltd., presently holds a permit under which gas produced from fields in the Peace River area is being removed from the Province. This gas, together with gas produced in British Columbia, is distributed in the interior and south-western British Columbia and delivered at Sumas at the international boundary to Pacific Northwest Pipeline Corporation for use in the Pacific north-west States.

Gas Supply Contracts

Westcoast has gas purchase contracts for 100 per cent of the gas in the Savanna Creek field. The initial price to be paid for residue gas is 11½¢ per Mcf, increasing to 20.44¢ per Mcf in 1978 (on a 14.4 psia pressure base).

With respect to the Calgary field the applicant has gas purchase contracts with Jefferson Lake Sulphur Company and Merrill Petroleums Limited and covering approximately 70 per cent of the gas in the field. The purchase price for gas ranges from 14¢ per Mcf, increasing to more than 19¢ per Mcf (on a 14.4 psia pressure base). The applicant also introduced evidence to the effect that it was negotiating with producers in the Wimborne Field to purchase their gas.

The Jefferson Lake Sulphur Company (1), which supported the application of Westcoast, is an American company extensively engaged in the production and sale of sulphur in the United States, and in the exploration for oil and gas with relation to the sulphur business. The Company controls a large percentage of the drilling and producing rights in the Calgary Field. This Company proposes to construct and own the Calgary processing plant and will have a half interest in the Coleman processing plant.

Gas Sales Contracts

Westcoast has a contract to sell to Pacific Northwest Pipeline Corporation 1.297 trillion cubic feet of gas at an annual volume of 55 billion cubic feet and a maximum daily volume of 170 million cubic feet. Mr. Kayser, Chairman of the Board of Pacific Northwest Pipeline Corporation and the President of El Paso Natural Gas Company, which owns a more than 99 per cent interest in Pacific Northwest Pipeline Corporation, supported Westcoast's application by presenting evidence as to the present and future potential markets for gas on the United States west coast. He also referred to the network of pipe lines that El Paso and Pacific Northwest have connecting and servicing this market. He stated that Pacific Northwest and El Paso were ready, willing and able

(1) Since the hearing of Westcoast application, Jefferson Lake Sulphur Company has transferred its Canadian contracts and agreements, leaseholds, plants and facilities and completed wells to the Jefferson Lake Petrochemicals of Canada Limited. Six hundred thousand (600,000) common shares of Jefferson Lake Petrochemicals of Canada Limited were sold to the public, fifty per cent of which were marketed in Canada and fifty per cent in the United States. Jefferson Lake Sulphur Company own 69 per cent of the outstanding shares of Jefferson Lake Petrochemicals of Canada Limited.

to take a small amount of gas or a large amount of gas in whatever amount was best for the Canadian economy. Pacific Northwest Pipeline Corporation has agreed to pay Westcoast for gas delivered at the international border a price equivalent to the full cost of service including cost of gas, all gathering, processing and transmitting costs and including a rate of return on all facilities at the rate of 7½ per cent per annum.

Protection of Alberta Requirements

Westcoast, through its subsidiary Westcoast Transmission Company (Alberta) Ltd., agrees to make available and deliver to any purchaser of gas from Westcoast (Alberta) such volumes of gas in each year as may be required to meet demands which cannot be reasonably supplied from gas supplies otherwise available in the Province, at a price for the gas delivered equal to the sum of the price paid by Westcoast to the producer of such gas and the costs incurred by Westcoast with respect to the gas, including gathering, transportation, processing and treatment costs. If the volume of the gas to be delivered cannot be agreed upon then the volume shall be fixed by the Oil and Gas Conservation Board. If the price to be paid for the gas cannot be agreed upon, the price shall be fixed by the Board of Public Utility Commissioners.

ALBERTA AND SOUTHERN APPLICATION

Alberta and Southern seeks a permit to acquire and remove from the Province over a period of 25 years a total of 4.2 trillion cubic feet of gas at maximum rates of 167.9

billion cubic feet per annum and 500 million cubic feet per day. The Company proposes to take the gas in accordance with various purchase contracts and agreements from the following fields: Waterton-Castle River, Crossfield, Sarcee, Westerose South (Dick Lake), Pine Coulee, Minnehik-Buck Lake, Homeglen-Rimbey, Pembina, Paddle River and Round Valley (Lobstick). In addition, the applicant has options under which it may purchase gas from undiscovered reserves in areas covering a large part of the south-western portion of the province.

The 4.2 trillion cubic feet, with the exception of small amounts for British Columbia communities, will be removed to the United States to supply markets chiefly in California and Montana.

The applicant will use facilities to be constructed by The Alberta Gas Trunk Line Company Limited to take gas from field gathering points for delivery to S & M Pipe Lines Limited at a point adjacent to the Alberta-British Columbia boundary, for gas going to British Columbia communities and California, and for delivery to Canadian-Montana Pipeline Company at a point adjacent to the Alberta-Montana boundary for gas going to Montana. Both the aforesaid pipe line companies are incorporated by special Act of the Parliament of Canada with powers to export gas interprovincially and internationally.

S & M Pipe Lines Limited will build a 36-inch line through British Columbia from the terminus of The Alberta Gas Trunk Line Company Limited line at the Alberta-British

Columbia boundary in the Crowsnest area to connect with a line to be constructed in the United States by the Pacific Gas Transmission Company from a point adjacent to the British Columbia-Idaho boundary.

Alberta and Southern Gas Co. Ltd. is incorporated under the laws of the Province of Alberta and is a wholly owned subsidiary of the Pacific Gas and Electric Company of San Francisco, California. Other sponsors of the Alberta and Southern project are Canadian Bechtel Limited, Blyth and Company, investment bankers of San Francisco, Canadian Western Natural Gas Company Limited, Northwestern Utilities, Limited and Montana Power Company. Its principle function is as a gas purchaser.

Pacific Gas and Electric Company is the largest utility of its kind in the United States, serving electricity and gas markets in northern and central California, particularly in the San Francisco area. Pacific Gas and Electric Company operates a network of almost 20,000 miles of transmission and distribution lines to provide gas service to nearly a million and a half customers.

S & M Pipe Lines Limited was incorporated by an Act of Parliament in 1955 and recently has been acquired by the Alberta and Southern sponsors. It is estimated that $38,200,000 of its capital will be required initially to provide transport facilities to deliver gas from The Alberta Gas Trunk Line Company Limited system to the Pacific Gas Transmission Company system. About 75 per cent of this amount will be raised from the sale of bonds and 25 per cent from common stock. It is intended that 50 per cent of the common stock will be owned by Pacific Gas Transmission Company and the balance offered to the Canadian public.

Pacific Gas Transmission Company (incorporated in the State of California) will deliver gas from the international border across portions of Idaho, Washington and Oregon to the California border. Some $123,500,000 will be required initially to provide transport facilities for the expected volumes of gas to be received from S & M Pipe Lines Limited. It is anticipated that the capitalization will be approximately 75 per cent bonds and term loans, 8 per cent interim notes (convertible into preferred stock) and 17 per cent common stock. Of the latter Pacific Gas and Electric Company will own about 50 per cent; Blyth and Company Incorporated, 7 per cent; Bechtel Corporation, 9 per cent; Canadian Western Natural Gas Company and Northwestern Utilities, Limited, 7 per cent and Montana Power Company 2 per cent. The balance of 25 per cent will be offered on a preferential basis to the Canadian public. No stock for promotional purposes will be issued to the original investors.

Gas Supply Contracts

Alberta and Southern has negotiated some 102 contracts and agreements with 73 different companies in the fields and areas mentioned previously, covering some 552.3 million cubic feet of gas per day. The price to be paid for the gas is 13½¢ per Mcf through June 30, 1961, increasing to 17¢ per

Mcf on June 30, 1968, and to 21¢ on July 1, 1983, at a base pressure of 14.73 pounds per square inch. In the case of Westerose South the pressure base is 14.4 psi, with the same price schedule. Prices commencing July 1, 1968, are subject to renegotiation. Provision is also made for adjusting the price if the Canadian dollar is at a premium of more than 5 per cent or a discount of more than 5 per cent with the United States dollar.

This applicant also has options covering future discoveries of gas in the areas of the south-western part of the Province with 12 companies, and covering an additional 963.1 million cubic feet per day if all of the gas is discovered, offered and accepted.

Alberta Gas Sales Contracts

Alberta and Southern has contracted for the sale of 31 million cubic feet per day of gas to the Canadian Montana Pipe Line Company and 429 million cubic feet per day to the Pacific Gas Transmission Company, both volumes being on a 90 per cent load factor, take or pay basis. The price to be paid for the gas is the weighted average cost to Alberta and Southern plus a monthly cost of service charge to the appropriate point of delivery.

Pacific Gas Transmission Company, in turn, has an agreement with the Pacific Gas and Electric Company that the latter will take on a cost of service basis all gas received by Pacific Gas Transmission Company from Alberta and Southern less any sales en route.

Protection of Alberta Requirements

Alberta and Southern has entered into a contract with Canadian Western Natural Gas Company Limited and Northwestern Utilities, Limited (hereinafter called the "utilities") whereby the utilities, after making maximum use of their other sources of supply would be given first call on reserves controlled by the Alberta and Southern in order to meet

(a) the actual annual gas requirements of their domestic, commercial and small industrial customers, and

(b) the estimated maximum daily natural gas requirements for their large industrial customers (using an average of over 500 Mcf per day) as shown on a schedule attached to the contract.

The schedule indicates the total large industrial requirements of the utilities in 1957 to be in the order of 31 billion cubic feet per year with a maximum daily rate of 114 million cubic feet, increasing to 125 billion cubic feet per year in 1986 and a maximum day requirement of 436 million cubic feet. Total estimated large industrial requirements from 1957 to 1986 are 2.464 trillion cubic feet.

The gas to be supplied to the utilities is divided into two categories:

(1) annual requirements of base load gas at not less than a 70 per cent load factor to be purchased at a price equal to the weighted average price paid by Alberta and Southern in the Province for

natural gas in the month such gas is delivered plus an appropriate transportation charge;

(2) additional or peak load gas to be purchased at 1.3 times the weighted average field price paid by Alberta and Southern in the Province in the month the additional gas is delivered plus an appropriate transportation charge, or, alternatively, the utilities may pay back in kind 1.3 cubic feet of gas for every additional cubic foot taken (such payment gas to be delivered at the mutual convenience of the parties).

With respect to the appropriate transportation charge for both categories of gas, Mr. Horton, General Manager of Alberta and Southern, under cross examination by Mr. S. J. Helman, Q.C., for the City of Calgary and other communities served by Canadian Western, stated the charge would be computed by determining the average cost of transporting gas through the facilities of The Alberta Gas Trunk Line Company Limited expressed in cents per Mcf per mile and multiplying such cost by the distance to the nearest field up-stream, which Alberta and Southern has under contract, from the point at which the utility would take delivery of gas.

INTERVENERS

At each of the hearings, the other applicant appeared as an intervener. Other interveners that appeared at both hearings were Canadian Western Natural Gas Company Limited, Northwestern Utilities, Limited, City of Calgary, The Alberta

Gas Trunk Line Company Limited, Trans-Canada Pipe Lines Limited, Southern California Gas Company, Southern Counties Gas Company and C. E. Smith who appeared representing the public interest. At the Alberta and Southern hearing, the City of Edmonton also was an intervener and Mr. Helman who appeared for the City of Calgary stated that he was also representing other communities being served by the Canadian Western system. At the Westcoast hearing, the Town of Coleman presented a brief through Mayor N. E. Frank Aboussafy who was called as a witness by Westcoast. During the Alberta and Southern hearing, submissions were also made on behalf of North Canadian Oils Limited, Shell Oil Company of Canada, Limited and The Consolidated Mining and Smelting Company of Canada Limited.

Some of the representations of interveners bear directly upon matters dealt with in the applications, such as reserves, local requirements, etc., and can be dealt with when those phases of the applications are considered. Other representations of a more incidental nature require separate consideration.

Following the termination of the hearing, written arguments were received from each applicant, the City of Calgary and Trans-Canada Pipe Lines Limited.

The Alberta Gas Trunk Line Company Limited

Each applicant had informed The Alberta Gas Trunk Line Company Limited (herein called "Trunk Line") of the facilities which it would require to transport gas within the Province.

Mr. J. C. Mahaffy, General Manager, appeared on behalf of Trunk Line at each of the hearings. In each case he made a statement with respect to his Company's position that it was not supporting or opposing the application, and that it reserved the right to change the route and design of the facilities proposed by the applicant, as it may be deemed necessary, to supply not only the requirements of the applicant but also to supply local markets and other export markets.

He stated further that his Company had not entered into a transportation agreement with either applicant, but did not anticipate any difficulty in making such arrangements.

With respect to the Westcoast application, Trunk Line objected to the proposal that a subsidiary company, Westcoast Transmission Company (Alberta) Ltd., would build the sour gas line from Savanna Creek to Coleman for two reasons:

(1) The plan might result in the loss of Provincial legislative and administrative control of the applicant's proposed gas operations and facilities within the Province.

(2) Trunk Line is frankly apprehensive that the proposed sour gas line, if constructed and operated by Westcoast Transmission Company (Alberta) Ltd. will be extended from one sour gas field to another and thus place the transportation of gas in the Foothills area within

the control of Westcoast rather than Trunk Line. In that event Trunk Line would be unable to fulfil adequately what it considers to be its future obligations to the gas producers and the gas consumers of the Province.

Mr. Mahaffy also recommended that it should be made clear, preferably in a condition to any export permit, that the permittee will make any pipe line gas transported for it by Trunk Line available at reasonable prices for farms or other small users which may make arrangements with Trunk Line to tap Trunk Line's facilities in order to take delivery of such gas.

Trans-Canada Pipe Lines Limited

Trans-Canada opposed both applications on the grounds that if they were granted there would not be sufficient reserves of gas to look after the requirements of the Province of Alberta and the other Canadian requirements and, further, that the granting of the applications would place the control of virtually all of the foreseeable gas reserves of the Province in the hands of large American corporations with material benefits to the United States and to the detriment of the Canadian economy.

Trans-Canada also contended that the Board did not have the authority to grant an export permit to a market outside of Canada. The Board is of the opinion that it makes no difference to its authority whether the gas to be removed from the Province is to be used within or outside Canada and that if Alberta and Canadian requirements are protected it has the right, with the approval of the Lieutenant Governor in Council, to issue a permit. Any permittee, of course, would have to obtain a licence to export under The Exportation of Power and Fluids and Importation of Gas Act. The Board believes, however, that the Federal authorities would issue a licence once they were satisfied that the gas to be exported was surplus to Canadian requirements and that Canadian gas going to the United States would be sold at the point of entry at a price which would not discriminate against Canadian consumers, having regard to load factors and other pertinent circumstances.

Trans-Canada filed with the Board an estimate of its future requirements and this is discussed in Appendix C which deals with Canadian markets.

The City of Calgary

The City of Calgary opposed any export of gas to the United States at the present time. The City contended that the established reserves and the trends in reserves are required to meet Alberta and Canadian requirements and would not support export out of Canada.

The City was of the opinion that the cost of export to the United States should not be permitted to change the price paid by Alberta consumers and that the price paid for gas by Alberta consumers should be on the same basis as if no export had been permitted. The City also was fearful that, with the recent upward trend in the percentage of sour gas reserves, more sulphur would be produced than could be marketed if the fields were produced in accordance with their potential deliverability.

Town of Coleman

The Town of Coleman in its brief urged that the benefits to that community resulting from the construction and operation of a processing plant be counted in support of the Westcoast application. Having been dependent solely on the coal industry the towns in the Crowsnest Pass are so hard hit that their very existence may depend on the plant and pipe line construction. In the meantime the municipal machinery and services are available. The number of men in Coleman in employment directly connected with coal has fallen from 1,250 in 1952 to less than 200. In the Pass there are 1,604 men receiving unemployment benefits, and among them are classified workers such as welders and mechanics, as well as common laborers.

North Canadian Oils Limited

The brief of North Canadian Oils Limited has bearing only on the application of Alberta and Southern. This company has a gas pipe line running from a point near Wabamun to Hinton. Its gas is produced in the Alexander Field and Calihoo area and delivered to the North Canadian line by Mid-Western Industrial Gas Limited. The proposed line carrying Alberta and Southern gas southward from the

Windfall area would cross the North Canadian line. This intervener pointed out that the Alberta and Southern project would cause an increase in the well head price of gas in the area tributary to the North Canadian pipe line. However, it would stimulate the search for and development of additional reserves in the area and would assure North Canadian and its customers of further supplies when necessary either from these additional reserves or from the line carrying Alberta and Southern gas. Also, it is possible that profitable use for North Canadian's surplus capacity could be found in transporting gas for Alberta and Southern. After weighing the pro's and con's, this intervener is in favor of Alberta and Southern.

The Consolidated Mining and Smelting Company of Canada Limited

The intervener, The Consolidated Mining and Smelting Company of Canada Limited, also was concerned about the price of gas in Alberta. It stated that it did not oppose "export" of natural gas, but submitted that any permit granted should be subject to the condition that the permittee will supply gas to industry within the Province at reasonable prices, having regard to the disadvantage that industry suffers in Alberta in comparison to its competitors in the export markets. This intervener operates a nitrogen plant at Calgary at which 280 persons are employed. It manufactures chemical fertilizers, a large part of which is exported. One-quarter of its market is in the States of Washington, Oregon and Idaho. Here its competitive position is difficult because of both the cost of transportation to market and competition with products of a new, modern plant.

Westcoast Transmission Company Limited

Westcoast opposed the application of Alberta and Southern on the grounds that the latter had not demonstrated it had adequate reserves to meet the deliverability for the Alberta utilities and its own requirements and that no provision had been made to supply Trans-Canada's additional requirements for its Canadian markets.

Further, Westcoast claimed that because Alberta and Southern was a new project requiring the construction of substantial pipe line facilities through territories and markets presently served by existing pipe lines, a considerable length of time might elapse before it received the necessary approval from the Federal Power Commission. On the other hand, Westcoast claimed its proposal involved a relatively small supply of gas which could be imported through the facilities of Pacific Northwest Pipeline Corporation and El Paso Natural Gas Company with a minimum of additional facilities to be constructed by the latter companies.

Alberta and Southern Gas Co. Ltd.

Alberta and Southern opposed Westcoast's application on the grounds that the only reserves Westcoast had under contract were the Calgary and Savanna Creek fields and that the contract between the Westcoast Transmission Company Limited and Westcoast Transmission Company (Alberta) Ltd., whereby the latter company would sell gas to Canadian Western Natural Gas Company Limited, was meaningless because no gas would be available from the Calgary field unless Westcoast was able to cut off its deliveries to its United States customer.

Alberta and Southern also contended the granting of the Westcoast application would create a monopoly both as to production and marketing of gas in Alberta and British Columbia and the Western United States. Reference was made to Westcoast's present pipe line system connecting reserves in the Peace River area to the United States and to the proposed line from the southern Alberta-British Columbia boundary to the United States with an ultimate capacity of 660 million cubic feet per day. Alberta and Southern suggested the present application was merely to get Westcoast's foot in the door and eventually the company would want to hook up with its Peace River system which would give it a pipe line ring from Sumas, Washington, north through British Columbia, across to the Peace River area of Alberta, then south through Alberta and the Crowsnest Pass to Kingsgate, British Columbia. Further reference was made to the marketing areas served by El Paso Natural Gas Company and Pacific Northwest Pipeline Corporation which include all of California, Oregon, Washington, Arizona and parts of New Mexico, Wyoming, Colorado and Utah, and to the fact that the acquisition of Pacific Northwest Pipeline Corporation by El Paso Natural Gas Company was the subject to an anti-trust suit brought by the United States Federal authorities.

FINDINGS

The Board having publicly heard the applications under The Gas Resources Preservation Act, 1956, of Alberta and Southern Gas Co. Ltd. and Westcoast Transmission Company Limited, having studied the evidence submitted at the public hearings, and having regard to the advice of its staff, to its own knowledge, and to its responsibilities under the Act, finds as follows:

I IN THE MATTER OF THE ESTABLISHED RESERVES OF GAS IN ALBERTA

The Board estimates the established reserves of gas in Alberta as of March 31, 1958, to be 22.5 trillion cubic feet (at 14.4 psia and 60°F) or the equivalent of 23.3 trillion cubic feet when converted to a common heating value of 1,000 Btu per cubic foot.

> The present estimate represents an increase of some 4.2 trillion cubic feet since the Board's last estimate of September 30, 1956. About one half of the increase is due to new discoveries, mostly in the foothills region of the Province, with the remainder being due to development of previous discoveries. Of the 23.3 trillion cubic feet some 1.3 trillion cubic feet represent reserves presently considered beyond economic reach, about 1.2 trillion cubic feet lie in the Peace River area of Alberta, leaving 20.8 trillion cubic feet as economically available gas in the remainder of the Province. Details of the reserve estimate appear in Appendix A and are illustrated in Figure E-3 of Appendix E.

II IN THE MATTER OF THE TRENDS IN EXPLORATION AND THE GROWTH OF RESERVES OF GAS IN ALBERTA

The Board believes that a reliable relationship confirmed by experience has now been developed between the number of wildcat wells drilled and the new gas reserves discovered. It confidently expects that for some time to come new gas reserves will be discovered at an average rate of about 6 billion cubic feet per wildcat well or, with the drilling of some 400 wildcat wells per year, at a rate of about 2.4 trillion cubic feet per year. Given proper incentive for exploration the Board believes such a rate of growth will continue for the next 15 to 20 years and that some 51 trillion cubic feet of new reserves will be discovered during the period 1958-1987.

> A detailed geological and statistical analysis of the trends in growth of reserves is presented in Appendix B. The amount by which newly discovered reserves are underestimated in the early years is also analyzed to indicate that, on the average, some 6 years is required before a reserve is fully evaluated. The present total estimate of 23.3 trillion cubic feet is known to be conservative and believed to be low by about 4.5 trillion cubic feet. Until this 4.5 trillion cubic feet of reserve is developed and can be assigned to the known fields it cannot be included with the established reserves.

III IN THE MATTER OF THE PRESENT AND FUTURE REQUIREMENTS OF ALBERTA FOR GAS AND THE PRESENT EXPORT COMMITMENTS

The Board estimates the actual requirements for Alberta for gas for the 30 year period January 1, 1958, to December 31, 1987, to be 8.0 trillion cubic feet with a 1987 peak day requirement of some 2,000 million cubic feet. For that part of the Province excluding the Peace River area the corresponding figures are 7.7 trillion and some 1,920 million cubic feet. Present remaining export commitments total some 5.7 trillion cubic feet of which about 4.9 trillion cubic feet is the commitment from the part of the Province excluding the Peace River area.

> Estimates received in evidence and studies of the Board staff were found to be in good general agreement. Full details appear in Appendix C with a treatment of an estimate by "formula" method in Appendix E.

IV IN THE MATTER OF THE MEETING OF THE 1958-1987 REQUIREMENTS OF ALBERTA TOGETHER WITH THE PRESENT EXPORT COMMITMENTS

The Board estimates that gas reserves totalling some 11.3 trillion cubic feet are necessary to meet the annual and peak day requirements of Alberta for the 30 year period 1958-1987.

The Board believes that the future requirements of and the export commitments from the Peace River area of the Province can most logically be met from the established and the future reserves of that area.

Reserves of the order of 10.7 trillion cubic feet are estimated to be necessary to meet the annual and peak day requirements of that part of the Province excluding the Peace River area for the 30 year period 1958-1987. Having regard to the reliance it now places on the trends in growth of reserves the Board considers that full and proper protection is afforded to this major part of Alberta by the reservation of some 9.3 trillion cubic feet from established reserves. The 9.3 trillion cubic feet is sufficient to meet annual requirements for 26 to 30 years and the peak day requirements for at least 25 years. The small remaining requirement of 1.4 trillion cubic feet is allocated against future reserves.

A further established reserve of the order of 5.7 trillion cubic feet is required to meet present export commitments from that part of the Province exclusive of the Peace River area.

> The problem of meeting the 1958-1987 requirements of Alberta and the present export commitments is given detailed study in Appendix D through comprehensive illustrative deliverability schedules. The problem is also analyzed by an alternative "formula" method in Appendix E. Both studies lead to the same general result. A pictorial representation is presented in Figure E-3.

V IN THE MATTER OF "CANADIAN PREFERENCE" AND THE CONTRACTABLE AND LONG TERM REQUIREMENTS OF CANADIAN MARKETS BEYOND ALBERTA

The Board considers that Canadian requirements beyond the Province and within the range of economic feasibility should be protected for 25 years and that this can be achieved by the reservation of the immediately contractable future requirements from current established reserves and the reservation of the balance of the requirements from future reserves.

At this time the Board considers that the present and future Canadian requirements in British Columbia can be met from British Columbia sources and committed export from Alberta to British Columbia.

Canadian requirements east of Alberta are now being served by Trans-Canada Pipe Lines Limited and Saskatchewan Power Corporation. Only Trans-Canada has indicated future

Canadian requirements beyond the authorized export. The Board estimates, and Trans-Canada concurs, that the immediately contractable future requirements of Trans-Canada are some 1.5 trillion cubic feet. The Board considers 4.5 trillion cubic feet to be a reasonable estimate of the balance of the 25 year Canadian requirements of Trans-Canada (in addition to the 4.5 trillion cubic feet now under permit and the 1.5 trillion cubic feet considered to be contractable).

> Details of the estimates and evidence received by the Board at the hearings and results of its own studies appear in Appendix C. A graphical representation of the requirements is given in Figure E-3 of Appendix E.

VI IN THE MATTER OF THE MEETING OF THE CONTRACTABLE AND LONG TERM REQUIREMENTS OF CANADIAN MARKETS BEYOND ALBERTA

The Board believes that the immediately contractable portion of the Canadian requirements of Trans-Canada Pipe Lines Limited may be protected (both as to annual and peak requirements) by the reservation of some 1.7 trillion cubic feet of established gas reserves from surplus declaration. Such reservation has been made and will be continued until December 31, 1958, to afford Trans-Canada Pipe Lines Limited the opportunity to contract for the gas and to file an application for its export from Alberta. The December 31, 1958, date may be changed to a later date if Trans-Canada upon application satisfies the Board that it is unable to contract for the gas on reasonable terms.

The long term Canadian requirements of Trans-Canada

Pipe Lines Limited require some 5.6 trillion cubic feet of gas reserves for the protection of both the annual and peak requirements. The Board is confident that full protection is afforded these requirements from the future reserves.

The Board contemplates periodic reviews of Canadian requirements beyond the Province and a continuation of the policy of reserving the immediately contractable requirements from surplus declaration and the long term requirements from future reserves.

> The problem of meeting the contractable and the long term Canadian requirements of Trans-Canada Pipe Lines Limited is dealt with in detail through illustrative deliverability schedules in Appendix D. An alternative analysis, leading to the same general result, is presented in Appendix E. A pictorial representation is provided in Figure E-3.

VII IN THE MATTER OF GAS SURPLUS TO THE 1958-1987 REQUIREMENTS OF ALBERTA, THE PRESENT EXPORT COMMITMENTS AND THE 1958-1982 CANADIAN REQUIREMENTS BEYOND ALBERTA

The Board estimates that, of the established reserves of 23.3 trillion cubic feet of gas, some 4.1 trillion cubic feet is surplus to the present and future requirements of Alberta, the present export commitments and the immediately contractable future Canadian requirements of Trans-Canada.

Of the future reserves now estimated at some 51 trillion cubic feet, some 44 trillion cubic feet is surplus to the presently estimated 30-year needs of Alberta and the 25-year other Canadian requirements. This surplus in future reserves will require revision from year to year to reflect changes in the estimates of both the future reserves and the future Alberta and other Canadian requirements. It is anticipated that much of this surplus future gas will become available for export.

> Details of the computation of these surplus amounts and of the fields in which the surplus established reserves are located are presented in Appendices D and E. A pictorial representation of the surplus gas is shown in Figure E-3 of Appendix E.

VIII IN THE MATTER OF THE DISPOSITION OF THE APPLICATIONS OF ALBERTA AND SOUTHERN GAS CO. LTD. AND WESTCOAST TRANSMISSION COMPANY LIMITED

The Board finds that the quantity of gas applied for by each applicant is in excess of that which can be met from surplus established reserves under contract to the applicant. The Board, therefore, cannot grant either application at this time.

The Board is prepared, with the approval of the Lieutenant Governor in Council, to continue both applications to December 31st, 1958, to afford each of the applicants the opportunity of filing amendments to its application for the purpose of adjusting the quantities of gas to be removed from the Province to correspond to the declared surplus. The Board refers the applicants to the detailed analyses of the surplus in Appendices D and E for general guidance in this respect.

Upon receipt of an amending application the Board would call a public hearing. At the hearing the Board would expect to receive evidence of

(a) contracts for any surplus gas additional to that under contract at the time of the hearing of the original application,

(b) any changes contemplated in the design, route and costs of the proposed pipe line and other facilities,

(c) an undertaking by The Alberta Gas Trunk Line Company Limited for the construction of the appropriate facilities required in Alberta.

The Board would then, with the approval of the Lieutenant Governor in Council, be prepared to issue a permit or permits, subject to suitable terms and conditions, to one or both of the applicants covering gas declared surplus and which the applicant has under contract.

If Alberta and Southern Gas Co. Ltd. does not file with the Board, on or before December 31st, 1958, an amendment to its application for the purpose set out above, its application shall be deemed to be dismissed.

If Westcoast Transmission Company Limited does not file with the Board, on or before December 31st, 1958, an amendment to its application for the purpose set out above, its application shall be deemed to be dismissed.

IX IN THE MATTER OF INTEGRATION AND THE MEETING OF THE REQUIREMENTS OF THE PROVINCE AND OF EXPORT GENERALLY

The Board believes that more can be accomplished in the interests of all parties concerned, including the Alberta consumers, if the Alberta utility companies, the producers of gas, The Alberta Gas Trunk Line Company Limited and the exporters of gas from the Province, would work together to formulate

(a) an efficient method of coordinating production and integrating deliveries of gas, and

(b) an efficient and imaginative design for the expansion of the Alberta Gas Trunk Line facilities.

The illustrative delivery schedules in Appendix D present one method whereby, though coordination and integration, the gas reserves may be employed to supply Alberta and other Canadian requirements, the present export commitments, and the surplus gas might be utilized to supply additional export markets. Undoubtedly there are other methods.

The Board is prepared to meet with any of the interested parties to discuss alternative schemes for the coordination of the production and the integration of deliveries of gas, and the overall design of facilities to be constructed by The Alberta Gas Trunk Line Company Limited.

Respectfully submitted,

I. N. McKinnon,
Chairman.

D. P. Goodall, P.Eng.,
Deputy Chairman.

G. W. Govier, P. Eng.,
Board Member.

Dated at Calgary, Alberta,
this 15th day of September, 1958.

APPENDIX A

THE ESTABLISHED RESERVES OF GAS IN ALBERTA

In previous studies the Board has reported gas reserves on an actual Btu basis -- i.e. as volumes of gas at 14.4 psia and 60°F of known or estimated actual heating value. It has become apparent to the Board that it would be more useful and would lead to more consistent interpretation if such figures were adjusted to a common heating value of 1,000 Btu per cubic foot (14.4 psia and 60°F). Accordingly in this reserve study figures are presented both on the actual and the 1,000 Btu basis.

The Board, in a report issued January, 1957, estimated the established reserves of gas in the Province as at September 30th, 1956, to be 18.3 trillion cubic feet (actual Btu basis). Present studies by the Board and its staff and submissions by industry indicate a sizeable increase in these reserves. Established reserves as of March 31, 1958, with production discounted to December 31, 1957, are estimated to be 22.5 trillion cubic feet (actual Btu basis) or 23.3 trillion cubic feet (1,000 Btu basis). This represents an increase of some 4.2 trillion cubic feet since September, 1956.

Both Westcoast Transmission Company Limited and Alberta and Southern Gas Co. Ltd. submitted gas reserve estimates for certain fields in the Province in which they considered significant changes had taken place since the Board's 1957 estimate.

The reserve estimates submitted by Westcoast Transmission Company Limited covered eighteen fields. The net increase in reserves for these fields over that of the Board's January, 1957, estimate was some 4.1 trillion cubic feet giving a total of 22.4 trillion cubic feet (actual Btu basis) for what the company designated as proved reserves as of January 1, 1958. Evidence with respect to these estimates was presented at the Westcoast hearing by Dr. G. S. Hume, Dr. W. J. McPherson and P. R. Kutney of Westcoast Transmission Company Limited and by O. D. Boggs and Dr. J. C. Sproule of J. C. Sproule and Associates.

During the hearing of Alberta and Southern Gas Co. Ltd., gas reserve estimates were submitted on the Company's behalf by Ralph E. Davis and his associate J. M. Wege. The Davis estimate covered thirty fields, most of which were at least partly under contract or option to Alberta and Southern. The total reserve of these thirty fields as of January 1, 1958, was estimated at 10.2 trillion cubic feet (actual Btu basis). By the addition of the gas reserves previously estimated by the Board's staff for the remainder of the Province as of the same date, Mr. Davis arrived at a total provincial reserve of 23.1 trillion cubic feet (actual Btu basis).

During the Alberta and Southern hearing an independent estimate of gas reserves was also submitted by Mr. C. H. Keplinger, consultant for Shell Oil Company of Canada, Limited, for the holdings of Shell in the Waterton field. Mr. Keplinger also gave a preliminary estimate of the reserves for a discovery made after January 1, 1958, by Shell Oil

Company of Canada, Limited at Panther River.

The more intensive exploratory drilling in the Alberta foothills and adjacent areas west of the fifth meridian during the past two years has accounted for most of the important discoveries of new gas reserves. The study shows that about 2.2 trillion cubic feet are attributable to these new discoveries and 2.0 trillion cubic feet to expansion of previously known reserves. The major new discoveries were Innisfail, Lovett, Panther River, Pine Creek, Stolberg and Waterton. The greatest increase in previously known reserves is attributable to Bindloss, Calgary, Carbon, Harmattan East, Medicine Hat, Minnehik-Buck Lake, Savanna Creek, Westerose South and Wimborne. Offsetting these increases to some extent are decreases in the estimates for Harmattan-Elkton, Pembina, Pincher Creek and Windfall.

The total established reserves of gas in Alberta of 23.3 trillion cubic feet (1,000 Btu basis) may be classified as follows:

(1)	Reserves presently considered within economic reach in Peace River Area	1.0	Tcf
(2)	Reserves presently considered within economic reach in remainder of Province	21.0	Tcf
(3)	Reserves presently considered beyond economic reach	1.3	Tcf
	Total	23.3	Tcf

Table A-1 lists individually all reserves estimated by the Board at 10 billion cubic feet or greater plus some smaller reserves available for local use. The reserves are given both on an actual and on a 1,000 Btu basis. Reserves less than 10 billion cubic feet each, assumed to be of 1,000 Btu gas, are not listed separately but are shown as totals of 237 billion cubic feet within and 592 billion cubic feet beyond economic reach.

A brief description of Table A-1 is as follows:

Column	Presents
1.	Name of field or area. The location of the fields and areas are shown in Figure A-1.
2.	Geological formation or zone from which gas is obtained. The stratigraphic relationship of the formations is shown in Figure A-2.
3.	Estimated original gas in place expressed in billions of cubic feet at standard conditions.
4.	Discount to be applied to original gas in place (Column 3) to account for the gas left in the reservoir at abandonment.
5.	Discount to be applied, after that for reservoir loss, to account for surface loss. This factor includes (where applicable) allowance for gas flared, operational loss, field and/or plant fuel, and processing shrinkage attending the removal of carbon dioxide, hydrogen sulphide, propane and butanes plus.
6.	Estimated disposable gas reserves as at March 31, 1958, expressed in billions of cubic feet at standard conditions.
7.	Heating value of gas expressed in Btu per cubic foot (14.4 psia, 60°F) from actual analyses where available, otherwise estimated.
8.	Equivalent value of column 6 expressed on the basis of gas at 1,000 Btu's per cubic foot.

Comments With Regard to Certain Fields

INNISFAIL

This reserve was discovered in June, 1957, by Canadian Oil Companies Ltd. The field is situated about four miles south-west of the town of Innisfail. It is a Devonian oil field with production from the Leduc (D-3 reef) formation.

A small gas reserve of about ten billion cubic feet occurs in the Mississippian limestone and about three billion cubic feet is estimated for the Wabamun at the top of the Devonian. The main reserve occurs, however, in the Leduc formation. There is a small gas cap in the highest part of the Leduc reef but most of the gas in the reservoir is associated with oil. This gas contains about 20 per cent hydrogen sulphide and will require processing to make it suitable for pipe line. The gas production will be governed by the rate of oil production. The field is well situated with respect to proposed market outlets.

LOVETT RIVER

This is a one well field situated in the foothills about fifty miles west of the large Pembina oil field and about forty-one miles south of the town of Edson. The discovery well, B.A. Triad et al Lovett River 12-30, encountered gas in the Rundle formation of Mississippian age and recorded flows on drill stem tests at rates up to 17 million cubic feet per day. No oil or water was encountered.

Since only one well has been drilled to date on this structure the Board has arbitrarily assigned 1,100 acres as a factor in the gas reserve calculation. At present this reserve is considered by the Board to be uneconomic owing to its location being remote from any proposed market outlet. With further development, however, sufficient gas reserves might be proven to make it attractive for a pipe line.

PANTHER RIVER

The Panther River structure was proven productive of gas in the Nisku (D-2) formation of Devonian age early in 1958 by the drilling of the Shell Panther River No. 1 well in Legal Subdivision 5 of Section 19, Township 30, Range 10, West of the 5th Meridian. This location is about 28 miles north of the town of Banff. Recent reports indicate that, after deepening the well, gas was discovered in a Mississippian formation in a lower fault block. This deeper reserve has not been evaluated.

A previous well which was not drilled to a sufficient depth to reach the Devonian, together with seismic information, provides some control as to the extent of the structure. The Board is of the opinion that five sections can be considered as proven acreage and that further extension of the productive area will depend largely on the presence of a water column on the flanks of the structure. The gas of this reserve contains a high percentage of hydrogen sulphide and will require processing. It is fairly well situated, however, with respect to future market outlets.

PINE CREEK

This reserve was discovered by the drilling of Hudson's Bay Stanolind Fina Pine Creek No. 1 well early in 1957. The discovery well is situated about thirty-two miles north-west of the town of Edson. At the date of this report four productive gas wells have been drilled in the field. The gas is encountered in a Leduc (D-3) reef deposit of Devonian age. Drilling depth is approximately 11,000 feet and the maximum gross gas pay thickness is 230 feet. The wells drilled to date have not clearly defined the boundaries of the field and the 7,000 acres presently considered productive may be extended by further drilling. One well in the field encountered gas in the Wabamun (D-1) but this reserve is thought to be small.

STOLBERG

Triad B.A. Stolberg 6-10A, drilled in 1957, was the discovery well of this foothills structure situated about nine miles north of Nordegg townsite. To date no further drilling has been done on the structure.

Gas flows up to three and a half million cubic feet per day were reported from drill stem tests of several fault blocks of the Mississippian at a depth of approximately 13,000 feet. Since little is known as to the extent of the reservoir the Board has arbitrarily assigned 1,100 acres as a factor in its calculation of gas reserves. Until further reserves are established by drilling the Board considers this field to be beyond economic reach.

WATERTON

This field was discovered in January, 1957, by the drilling of the Shell Waterton No. 1 well and about three months later the Texaco Castle River A-3-4 well encountered gas in the same horizon about ten miles north-west of the discovery. Subsequent drilling indicates that these two wells are on a structural trend extending in a north-west--south-east direction for about 20 miles. Whether the reservoir is continuous over the full distance remains to be proven by further drilling. For the purpose of this report, however, the Waterton and Castle River reserves have been combined.

This major gas reserve is situated about fifteen miles west of the Pincher Creek Field in the south-western corner of the Province. The gas occurs chiefly in the Mississippian limestone but a smaller reserve of gas is known to be present in the Wabamun group of Devonian age in the northern end of the field. The gas from this field contains a relatively high percentage of hydrogen sulphide and will have to be processed for its removal before the gas will be suitable for market.

TABLE A - 1

OIL AND GAS CONSERVATION BOARD

ESTABLISHED RESERVES OF NATURAL GAS IN THE PROVINCE OF ALBERTA, MARCH 31, 1958(3)

(1) FIELD OR AREA	(2) ZONE	(3) ESTIMATED ORIGINAL GAS IN PLACE BCF	(4) RESERVOIR LOSS DISCOUNT PER CENT	(5) SURFACE LOSS DISCOUNT PER CENT	(6) DISPOSABLE GAS(3) BCF	(7) HEATING VALUE(4) BTU PER CU. FT.	(8) DISPOSABLE GAS (1000 BTU BASIS)(3) BCF	(9) REMARKS
Acheson	Viking	14.3(i) 14.1(ii)	25	5	10	1010(E)	10	(i) Original (ii) Less 0.2 Bcf produced to Dec. 31, 1957.
	Basal Blairmore	37.4(i) 36.9(ii)	20	15	25	1040	26	(i) Original (ii) Less 0.5 Bcf produced to Dec. 31, 1957.
	Leduc Solution	84.4(i) 78.0(ii)	45	25	30	1340	40	(i) Original (ii) Less 6.4 Bcf produced to Dec. 31, 1957.
Alexander	Basal Blairmore	52.5(i) 44.8(ii)	15	5	35	1090	38	(i) Original (ii) Less 7.7 Bcf produced to Dec. 31, 1957.
Alhambra	Belly River Solution	3.6	35	15	2	1000(E)	2	Presently considered beyond economic reach.
	Cardium Non-Associated	13.2	20	5	10	1000(E)	10	
	Cardium Solution	27.9(i) 27.4(ii)	35	15	15	1150(E)	17	(i) Original (ii) Less 0.5 Bcf produced to Dec. 31, 1957.
Antelope	Viking	10.5	20	5	8	1000	8	
	Banff	5.0	15	5	4	1000	4	
Athabasca	Lower Cretaceous	4.9(i) 4.1(11)	15	5	3.1	1010	3.1	Supplies local utility. (i) Original (ii) Less 0.8 Bcf produced to Dec. 31, 1957.
	Wabamun	3.5	10	5	3	980(E)	3	Wabamun presently considered beyond economic reach.
Athabasca East	Wabamun	1.7(i) 1.4(ii)	10	5	1.2	980	1.2	Supplies local utility. (i) Original (ii) Less 0.3 Bcf produced to Dec. 31, 1957.
Atlee-Buffalo	Viking	98.2	25	5	70	940	66	
	Basal Blairmore	92.2	20	5	70	960	67	
Beaver Creek.	Wabamun	40.4	10	45	20	970	19	
Beaverhill Lake	Viking	131.8(i) 131.6(ii)	20	5	100	980	98	Supplies local utility. (i) Original (ii) Less 0.2 Bcf produced to Dec. 31, 1957.
	Basal Blairmore	3.9	20	5	3	970(E)	3	

TABLE A - 1 (Continued)

(1) FIELD OR AREA	(2) ZONE	(3) ESTIMATED ORIGINAL GAS IN PLACE BCF	(4) RESERVOIR LOSS DISCOUNT PER CENT	(5) SURFACE LOSS DISCOUNT PER CENT	(6) DISPOSABLE GAS$^{(3)}$ BCF	(7) HEATING VALUE$^{(4)}$ BTU PER CU. FT.	(8) DISPOSABLE GAS (1000 BTU BASIS)$^{(3)}$ BCF	(9) REMARKS
Belloy	Cadotte	5.3	20	5	4	1000(e)	4	
	Notikewin	9.2	20	5	7	980	7	
	Gething	61.9	15	5	50	980	49	
	Mississippian	17.5	10	5	15	1100	16	
Bellshill Lake	Viking	5.6	25	5	4	1020	4	
	Blairmore Non-Associated	43.4	15	5	35	970	34	
	Blairmore Associated	2.8	15	15	2	970	2	Blairmore Associated and Solution reserves presently considered beyond economic reach.
	Blairmore Solution	39.6(i) 39.4(ii)	40	15	20	990(e)	20	(i) Original (ii) Less 0.2 Bcf produced to Dec. 31, 1957.
Big Lake	Blairmore	12.4	15	5	10	1070	11	
Bindloss	Viking	348.3(i) 346.9(ii)	15	5	280	930	260	(i) Original (ii) Less 1.4 Bcf produced to Dec. 31, 1957.
	Basal Blairmore	24.8	15	5	20	970	19	
Bittern Lake	Viking	1.4	25	5	1	1000(e)	1	
	Blairmore	29.3	10	5	25	1050(e)	26	
Black Butte	Bow Island	14.1	10	5	12	990	12	
	Jurassic	23.2(i) 13.7(ii)	20	5	8.6	980	8.4	(i) Original (ii) Less 9.5 Bcf produced to Dec. 31, 1957.
	Rundle	14.7	15	20	10	1000(e)	10	
Blueridge	Detrital	14.0	10	5	12	1080	13	
	Mississippian	1.3	20	5	1	1110	1	
Bonnie Glen	Leduc Associated	430.1(i) 431.5(ii)	10	15	330	1230	406	(i) Original (ii) Plus 1.4 Bcf injected to Dec. 31, 1957.
	Leduc Solution	606.0(i) 576.0(ii)	40	25	250	1230	308	(i) Original (ii) Less 30.0 Bcf produced to Dec. 31, 1957.
Bonnyville	Colony Associated	4.0(i) 3.2(ii)	15	5	2.5	960	2.4	Supplies local utility. (i) Original (ii) Less 0.8 Bcf produced to Dec. 31, 1957.

TABLE A - 1 (CONTINUED)

(1) FIELD OR AREA	(2) ZONE	(3) ESTIMATED ORIGINAL GAS IN PLACE BCF	(4) RESERVOIR LOSS DISCOUNT PER CENT	(5) SURFACE LOSS DISCOUNT PER CENT	(6) DISPOSABLE GAS$^{(3)}$ BCF	(7) HEATING VALUE$^{(4)}$ BTU PER CU. FT.	(8) DISPOSABLE GAS (1000 BTU BASIS)$^{(3)}$ BCF	(9) REMARKS
Bow Island	Bow Island	21.0	20	5	16	1090	17	CWNG storage reservoir.
Boyle-Mustang-Amisk Lake	Blairmore	7.0	25	5	5	980(E)	5	Presently considered beyond economic reach.
	Nisku	19.8	20	5	15	970	15	
Braeburn	Cadomin	26.3	20	5	20	1040	21	
	Triassic	7.9	20	5	6	1070	6	
	Permo-Penn	81.9	10	5	70	1010	71	
Braeburn West	Peace River	82.0	10	5	70	1000(E)	70	
	Cadomin	5.8	10	5	5	1040	5	
	Jurassic	3.9	15	10	3	1050(E)	3	
	Triassic	13.2	20	5	10	1070	11	
Brooks-Northeast	Bow Island	13.2	20	5	10	940(E)	9	Possible local supply.
	Basal Blairmore	13.1(i) 11.8(ii)	10	5	10	1010	10	Supplies Local Utility. (i) Original (ii) Less 1.3 Bcf produced to Dec. 31, 1957.
Brooks-Tilley	Milk River	36.9(i) 33.7(ii)	20	5	25	970	24	Supplies Local Utility. (i) Original (ii) Less 3.2 Bcf produced to Dec. 31, 1957.
	Basal Blairmore	3.9	20	5	3	1140	3	
Burnt River	Paddy	2.3	10	5	2	990	2	
	Bluesky	9.4	10	5	8	1000(E)	8	
Calahoo	Basal Blairmore	16.1	15	5	13	1040	14	
Calgary	Basal Blairmore	13.2	20	5	10	1000(E)	10	
	Elkton	719.0	10	15	550	1050	578	
	Wabamun	1333.0	10	60(i)	480	960	461	(i) High loss due to very high acid gas content.
Campbell-Namao	Basal Blairmore Associated	46.8(i) 47.2(ii)	10	5	40	1000(E)	40	(i) Original (ii) Plus 0.4 Bcf injected to Dec. 31, 1957.
	Basal Blairmore Solution	12.2(i) 10.8(ii)	40	15	5	990	5	(i) Orignal (ii) Less 1.4 Bcf produced to Dec. 31, 1957.
Carbon	Viking	3.9	20	5	3	1000(E)	3	
	Blairmore	257.6	10	5	220	1120	246	
Carson Creek	Beaverhill Lake	39.2	10	15	30	1000(E)	30	

TABLE A - 1 (CONTINUED)

(1) FIELD OR AREA	(2) ZONE	(3) ESTIMATED ORIGINAL GAS IN PLACE BCF	(4) RESERVOIR LOSS DISCOUNT PER CENT	(5) SURFACE LOSS DISCOUNT PER CENT	(6) DISPOSABLE GAS$^{(3)}$ BCF	(7) HEATING VALUE$^{(4)}$ BTU PER CU. FT.	(8) DISPOSABLE GAS (1000 BTU BASIS)$^{(3)}$ BCF	(9) REMARKS
CASTOR	VIKING	22.3	15	5	18	1020	18	
	BLAIRMORE	2.3	10	5	2	1050(E)	2	
CESSFORD	VIKING	98.7	20	5	75	1020	77	
	BASAL COLORADO	1021.0(I) 1020.0(II)	20	5	775	1000	775	(I) ORIGINAL (II) LESS 1.0 BCF PRODUCED TO DEC. 31, 1957.
	BASAL BLAIRMORE	289.7	20	5	220	1080	238	
CHIGWELL	BASAL BLAIRMORE	37.0	10	10	30	1000(E)	30	
CHINOOK RIDGE	PADDY	6.9	20	10	5	1000(E)	5	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	CADOTTE	24.7	10	10	20	1000(E)	20	
	NOTIKEWIN	24.7	10	10	20	1000(E)	20	
CHISHOLM	BLAIRMORE	11.7	10	5	10	1000(E)	10	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
CLIVE	VIKING	3.9	20	5	3	970(E)	3	
	BASAL BLAIRMORE	3.7	15	5	3	1000(E)	3	
	NISKU ASSOCIATED	9.2	10	15	7	1130	8	
	LEDUC ASSOCIATED	4.7	15	25	3	1190	4	
COLD LAKE	COLONY	5.1(I) 3.8(II)	25	5	2.4	980	2.4	SUPPLIES LOCAL UTILITY. (I) ORIGINAL (II) LESS 1.3 BCF PRODUCED TO DEC. 31, 1957.
COMREY	BOW ISLAND	53.0(I) 52.7(II)	10	5	45	920	41	(I) ORIGINAL (II) LESS 0.3 BCF PRODUCED TO DEC. 31, 1957.
CONNORSVILLE	VIKING	8.7	15	5	7	970	7	
	BASAL BLAIRMORE	13.6	15	5	11	1110	12	
CONTROL	VIKING	12.4	15	5	10	950(E)	10	
	BASAL BLAIRMORE	11.7	10	5	10	1010(E)	10	
COUNTESS	VIKING	65.8	20	5	50	950	48	
	BASAL BLAIRMORE	4.7	15	5	4	1010(E)	4	
CROSSFIELD	MISSISSIPPIAN	250.3	10	20	180	1050	189	
DIXONVILLE	GETHING	35.6	20	5	27	980	26	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.

TABLE A - 1 (Continued)

(1) Field or Area	(2) Zone	(3) Estimated Original Gas in Place BCF	(4) Reservoir Loss Discount Per Cent	(5) Surface Loss Discount Per Cent	(6) Disposable Gas(3) BCF	(7) Heating Value(4) BTU per Cu. Ft.	(8) Disposable Gas (1000 BTU Basis)(3) BCF	(9) Remarks
Donalda	Viking	14.9	15	5	12	950	11	Presently considered beyond economic reach.
	Detrital	2.5	15	5	2	970(e)	2	
Dowling Lake	Detrital	0.8(i) 0.5(ii)	20	5	0.3	1130	0.3	Supplies local utility. (i) Original (ii) Less 0.3 Bcf produced to Dec. 31, 1957.
Duchess	Viking	13.2	20	5	10	990	10	
	Basal Colorado	11.8	20	5	9	1010(e)	9	
Duhamel	Viking	4.8(i) 4.7(ii)	10	5	4	980(e)	4	(i) Original (ii) Less 0.1 Bcf produced to Dec. 31, 1957.
	Blairmore	2.3	10	5	2	1000(e)	2	Viking and Devonian gas is being injected into Leduc.
	Devonian	12.7(i) 11.5(ii)	35	15	6	1250	8	(i) Original (ii) Less 1.2 Bcf produced to Dec. 31, 1957. Injected 0.1 Bcf to Dec. 31, 1957. Net production 1.1 Bcf.
Duvernay	Viking	1.5 (i) 0.6(ii)	20	5	0.3	960	0.3	(i) Original (ii) Less 0.9 Bcf produced to Dec. 31, 1957. Supplies chemical plant.
Dyberg	Basal Belly River	3.5	10	5	3	930	3	
	Viking	9.4	10	5	8	980(e)	8	
	Basal Blairmore	3.7	15	5	3	1000(e)	3	
Elk Point	Blairmore	1.2(i) 0.8(ii)	25	5	0.5	970	0.5	Supplies local utility. (i) Original (ii) Less 0.4 Bcf produced to Dec. 31, 1957.
Enchant	Bow Island	7.0	25	5	5	950(e)	5	
	Ellis	2.6	20	5	2	980(e)	2	
	Detrital	1.3	20	5	1	970(e)	1	
	Rundle	3.9	20	5	3	1020	3	
Erskine	Viking	4.2	25	5	3	1020	3	
	Blairmore	20.0(i) 19.6(ii)	15	10	15	1070	16	(i) Original (ii) Less 0.4 Bcf produced to Dec. 31, 1957.
	Leduc Associated	30.6	10	20	22	1050(e)	23	
	Leduc Solution	17.7(i) 16.2(ii)	35	20	8	1090	9	(i) Original (ii) Less 1.5 Bcf produced to Dec. 31, 1957.

TABLE A - 1 (Continued)

(1) FIELD OR AREA	(2) ZONE	(3) ESTIMATED ORIGINAL GAS IN PLACE BCF	(4) RESERVOIR LOSS DISCOUNT PER CENT	(5) SURFACE LOSS DISCOUNT PER CENT	(6) DISPOSABLE GAS(3) BCF	(7) HEATING VALUE(4) BTU PER CU. FT.	(8) DISPOSABLE GAS (1000 BTU BASIS)(3) BCF	(9) REMARKS
Etzikom	Bow Island	153.1(i) 149.4(ii)	15	5	120	910	109	(i) Original (ii) Less 3.7 Bcf produced to Dec. 31, 1957.
	Basal Blairmore	1.4	25	5	1	990	1	
Excelsior	Viking	8.7	15	5	7	980(e)	7	
	Basal Blairmore Associated	38.6	10	5	33	950	31	
	Basal Blairmore Solution	7.2	35	15	4	950	4	
Fairydell-Bon Accord	Viking	119.8(i) 115.6(ii)	20	5	87	1000	87	(i) Original (ii) Less 4.2 Bcf produced to Dec. 31, 1957.
	Basal Blairmore	19.7	20	5	15	980	15	
Faust South	Gething	11.7	10	5	10	970	10	Presently considered beyond economic reach.
Fenn-Big Valley	Viking	17.5(i) 17.4(ii)	15	5	14	980(e)	14	(i) Original (ii) Less 0.1 Bcf produced to Dec. 31, 1957.
	Nisku Solution	185.2(i) 172.4(ii)	45	45	49	1120	55	(i) Original (ii) Less 12.8 Bcf produced to Dec. 31, 1957.
	Leduc Associated and Solution	10.2(i) 9.5(ii)	40	45	3	980	3	(i) Original (ii) Less 0.7 Bcf produced to Dec. 31, 1957.
Figure Lake	Viking	3.7	15	5	3	940	3	Presently considered beyond economic reach.
	Blairmore	9.2	20	5	7	980(e)	7	
	Nisku	26.3	20	5	20	970(e)	19	
Foremost	Bow Island	31.0(i) 25.2(ii)	10	5	21	930	20	(i) Original (ii) Less 5.8 Bcf produced to Dec. 31, 1957.
Fort Saskatchewan	Viking	162.0(i) 142.4(ii)	10	5	120	980	118	(i) Original (ii) Less 19.6 Bcf produced to Dec. 31, 1957.
Garrington	Viking	18.5	10	10	15	980(e)	15	
	Leduc	30.9	10	10	25	1000(e)	25	

TABLE A - 1 (Continued)

(1) Field or Area	(2) Zone	(3) Estimated Original Gas in Place BCF	(4) Reservoir Loss Discount Per Cent	(5) Surface Loss Discount Per Cent	(6) Disposable Gas(3) BCF	(7) Heating Value(4) BTU per Cu. Ft.	(8) Disposable Gas (1000 BTU Basis)(3) BCF	(9) Remarks
Ghost Pine	Blairmore	17.0	15	10	13	990(e)	13	
	Rundle	2.6	15	10	2	1050(e)	2	
Gilby	Viking Non-Associated	4.2	20	10	3	1200	4	
	Basal Blairmore	7.8	15	10	6	1140	7	
	Detrital	37.0	10	10	30	1000(e)	30	
	Mississippian	248.5	10	15	190	1060	202	
	Wabamun	6.9	10	20	5	1150	6	
Glen Park	Blairmore	9.2(i) 8.8(ii)	15	5	7	1120	8	(i) Original (ii) Less 0.4 Bcf produced to Dec. 31, 1957.
	Leduc Solution	17.5(i) 16.4(ii)	40	15	8	1230	10	(i) Original (ii) Less 1.1 Bcf produced to Dec. 31, 1957.
Golden Spike	Viking	4.4(i) 3.0(ii)	20	5	2	1030	2	(i) Original (ii) Less 1.4 Bcf produced to Dec. 31, 1957.
	Basal Blairmore	10.9(i) 10.0(ii)	15	5	8	1030	8	(i) Original (ii) Less 0.9 Bcf produced to Dec. 31, 1957.
	Wabamun	15.3(i) 13.3(ii)	10	15	10	1040	10	(i) Original (ii) Less 2.0 Bcf produced to Dec. 31, 1957.
	Nisku Associated	3.9	10	15	3	1200	4	
	Nisku Solution	12.3(i) 11.8(ii)	35	20	6	1200	7	(i) Original (ii) Less 0.5 Bcf produced to Dec. 31, 1957.
	Leduc Solution	127.8(i) 133.4(ii)	25	25	75	1270	95	(i) Original (ii) Less 6.5 Bcf produced to Dec. 31, 1957. Stored 12.1 Bcf to Dec. 31, 1957. Net storage 5.6 Bcf.
Goodwin Lake	Viking	3.9	20	5	3	1000(e)	3	
	Nordegg	30.9	10	10	25	1050	26	
Gordondale	Cadotte	58.5	10	5	50	980(e)	49	
	Notikewin	3.9	20	5	3	1000(e)	3	
	Gething	93.6	10	5	80	1030	82	
Grassy Island Lake	Viking	28.1	25	5	20	980(e)	20	
Hackett	Basal Blairmore	81.9	10	5	70	1080	76	

TABLE A - 1 (Continued)

(1) Field or Area	(2) Zone	(3) Estimated Original Gas in Place BCF	(4) Reservoir Loss Discount Per Cent	(5) Surface Loss Discount Per Cent	(6) Disposable Gas$^{(3)}$ BCF	(7) Heating Value$^{(4)}$ BTU per Cu. Ft.	(8) Disposable Gas (1000 BTU Basis)$^{(3)}$ BCF	(9) Remarks
Hairy Hill	Viking	2.8	25	5	2	960	2	
	Blairmore	17.4(i) 16.1(ii)	20	5	12	980	12	Supplies chemical plant. (i) Original (ii) Less 1.3 Bcf produced to Dec. 31, 1957.
Hamelin Creek	Cadotte	7.0	25	5	5	980(e)	5	
	Gething	3.7	15	5	3	990	3	
	Cadomin	40.9	10	5	35	1040(e)	36	
Hamilton Lake	Viking	56.8(i) 56.3(ii)	25	5	40	1020	41	(i) Original (ii) Less 0.5 Bcf produced to Dec. 31, 1957.
Harmattan-Elkton	Mississippian Non-Associated	76.4	10	20	55	1020(e)	56	
	Mississippian Associated	1124.5	10	20	810	1060	859	
	Mississippian Solution	179.6(i) 176.1(ii)	35	25	85	1260	107	(i) Original (ii) Less 3.5 Bcf produced to Dec. 31, 1957.
Harmattan-East	Mississippian Associated	152.9	10	20	110	1060	117	
Hercules	Viking	11.1	15	5	9	1030	9	
	Basal Blairmore	12.4	15	5	10	940	9	
Hilda	Medicine Hat	21.1	25	5	15	950(e)	14	
Holborne	Cardium	8.4	25	5	6	960	6	
	Basal Blairmore	25.0	20	10	18	1100(e)	20	
Homeglen-Rimbey	Leduc Associated	1013.0	10	20	730	1060	774	
	Leduc Solution	96.2(i) 91.9(ii)	40	25	40	1060	42	(i) Original (ii) Less 4.3 Bcf produced to Dec. 31, 1957.
Hussar	Viking	5.3	20	5	4	980(e)	4	
	Basal Colorado	42.1	25	5	30	1010	30	
	Blairmore	187.1	10	5	160	1090	174	
Innisfail	Mississippian	11.7	10	5	10	1060(e)	11	
	Wabamun	3.9	15	10	3	1150(e)	3	
	Leduc Associated	13.7	10	35	8	1000(e)	8	
	Leduc Solution	141.3(i) 141.0(ii)	40	35	55	1060	58	(i) Original (ii) Less 0.3 Bcf produced to Dec. 31, 1957.

TABLE A - 1 (Continued)

(1) FIELD OR AREA	(2) ZONE	(3) ESTIMATED ORIGINAL GAS IN PLACE BCF	(4) RESERVOIR LOSS DISCOUNT PER CENT	(5) SURFACE LOSS DISCOUNT PER CENT	(6) DISPOSABLE GAS(3) BCF	(7) HEATING VALUE(4) BTU PER CU. FT.	(8) DISPOSABLE GAS (1000 BTU BASIS)(3) BCF	(9) REMARKS
Joarcam	Viking Associated	65.8	20	5	50	1020	51	
	Viking Solution	51.9(i) 38.4(ii)	40	15	15	1070	16	Presently considered beyond economic reach. (i) Original (ii) Less 13.5 Bcf produced to Dec. 31, 1957.
Joffre	Viking Solution	35.5(i) 28.3(ii)	40	15	12	1170	14	Presently considered beyond economic reach. (i) Original (ii) Less 7.2 Bcf produced to Dec. 31, 1957.
	Basal Blairmore	6.6	20	5	5	1000(e)	5	Presently considered beyond Economic reach.
	Nisku Solution	104.2(i) 104.1(ii)	40	20	50	1240	62	(i) Original (ii) Less 0.1 Bcf produced to Dec. 31, 1957.
Jumping Pound	Rundle	786.5(i) 699.6(ii)	10	17	515	1020	525	(i) Original (ii) Less 89.7 Bcf produced to Dec. 31, 1957. Injected 2.8 Bcf to Dec. 31, 1957. Net Production 86.9 Bcf.
Kessler	Viking	70.1	25	5	50	970	49	
Kevisville	Leduc	18.5	10	40	10	960	10	Presently considered beyond economic reach.
Keystone	Basal Belly River	35.1	10	5	30	1000	30	
	Cardium Solution	72.2(i) 72.0(ii)	35	25	35	1140	40	(i) Original (ii) Less 0.2 Bcf produced to Dec. 31, 1957. Solution gas presently considered beyond economic reach.
	Blairmore	3.9	20	5	3	980(e)	3	
	Nordegg	5.9	10	5	5	1050(e)	5	
Lac La Biche	Viking	46.0	20	5	35	990	35	Presently considered beyond economic reach.
	Blairmore	12.4	15	5	10	990	10	
Leahurst	Basal Blairmore	8.8(i) 8.3(ii)	15	5	7.1	1080	7.7	(i) Original (ii) Less 0.5 Bcf produced to Dec. 31, 1957. Supplies local utility.

TABLE A - 1 (Continued)

(1) FIELD OR AREA	(2) ZONE	(3) ESTIMATED ORIGINAL GAS IN PLACE BCF	(4) RESERVOIR LOSS DISCOUNT PER CENT	(5) SURFACE LOSS DISCOUNT PER CENT	(6) DISPOSABLE GAS(3) BCF	(7) HEATING VALUE(4) BTU PER CU. FT.	(8) DISPOSABLE GAS (1000 BTU BASIS)(3) BCF	(9) REMARKS
Leduc-Woodbend	Viking	16.5(i) 15.9(ii)	20	5	12	1050	13	(i) Original (ii) Less 0.6 Bcf produced to Dec. 31, 1957.
	Blairmore	195.3(i) 193.2(ii)	25	10	130	1160	151	(i) Original (ii) Less 2.1 Bcf produced to Dec. 31, 1957. 14.0 Bcf (1000 BTU basis) presently considered beyond economic reach.
	Nisku Associated	36.6	10	15	28	1160	32	
	Nisku Solution	123.7(i) 88.0(ii)	25	30	40	1160	46	(i) Original (ii) Less 35.7 Bcf produced to Dec. 31, 1957.
	Leduc Associated	450.2(i) 421.8(ii)	15	15	300	1160	348	(i) Original (ii) Less 28.8 Bcf produced to Dec. 31, 1957. Injected 0.4 Bcf to Dec. 31, 1957. Net production 28.4 Bcf.
	Leduc Solution	189.7(i) 130.1(ii)	40	30	38	1160	44	(i) Original (ii) Less 59.6 Bcf produced to Dec. 31, 1957.
Lindbergh	Viking	3.2	35	5	2	970	2	
	Blairmore	4.6(i) 2.3(ii)	20	5	1	980(e)	1	(i) Original (ii) Less 2.2 Bcf produced to Dec. 31, 1957. Supplies salt plant.
Little Smoky River	Permo-Penn	2.5	15	5	2	1010(e)	2	Presently considered beyond economic reach.
	Mississippian	2.5	15	5	2	1030(e)	2	
	Leduc Associated and Solution	22.5(i) 22.2(ii)	35	30	10	960	10	(i) Original (ii) Less 0.3 Bcf produced to Dec. 31, 1957.
Lloydminster	Colony	18.8	40	15	3.4	920	3.1	12.7 Bcf produced from both zones to Dec. 31, 1957.
	Sparky	21.0	60	40	1.8	930	1.7	Supplies local utility.
Lone Pine Creek West	Wabamun	27.8	10	20	20	1050(e)	21	
Lovett	Rundle	86.4	10	10	70	1020	71	Presently considered beyond economic reach.

TABLE A - 1 (Continued)

(1) FIELD OR AREA	(2) ZONE	(3) ESTIMATED ORIGINAL GAS IN PLACE BCF	(4) RESERVOIR LOSS DISCOUNT PER CENT	(5) SURFACE LOSS DISCOUNT PER CENT	(6) DISPOSABLE GAS(3) BCF	(7) HEATING VALUE(4) BTU PER CU. FT.	(8) DISPOSABLE GAS (1000 BTU BASIS)(3) BCF	(9) REMARKS
Majeau Lake	Blairmore	2.6	20	5	2	980(e)	2	Presently considered beyond economic reach.
	Mississippian	11.7	10	5	10	1050(e)	11	
Malmo	Viking	3.7	15	5	3	980(e)	3	
	Basal Blairmore	9.0(i) 8.6(ii)	30	15	5	1100	6	(i) Original (ii) Less 0.4 Bcf produced to Dec. 31, 1957.
	Devonian Associated and Solution	18.6(i) 16.8(ii)	30	20	9	1100	10	(i) Original (ii) Less 1.8 Bcf produced to Dec. 31, 1957.
Manyberries	Bow Island	69.8(i) 66.5(ii)	20	5	50	920	46	(i) Original (ii) Less 3.3 Bcf produced to Dec. 31, 1957.
Mazeppa	Mississippian	19.6	10	15	15	1040	16	
Medicine Hat	Medicine Hat	2058.0(i) 1855.5(ii)	20	6.5	1350	950	1283	(i) Original (ii) Less 202.5 Bcf produced to Dec. 31, 1957.
	Bow Island	19.7	20	5	15	950(e)	14	
	Ellis	6.2	15	5	5	980(e)	5	
Millet	Blairmore	20.8	20	10	15	1000(e)	15	Presently considered beyond economic reach.
Minnehik-Buck Lake	Basal Blairmore	2.8	25	5	2	980(e)	2	
	Mississippian	352.7	10	15	270	1070	289	
Morinville	Viking	2.8	25	5	2	980(e)	2	
	Basal Blairmore	139.4(i) 120.9(ii)	15	5	95	1050	100	(i) Original (ii) Less 18.5 Bcf produced to Dec. 31, 1957.
Mountain Park	Triassic	29.2	10	5	25	1070(e)	27	Presently considered beyond economic reach.
Nevis	Blairmore	65.9	20	5	50	1170	59	
	Devonian	695.0	10	20	500	950	475	
New Norway	Viking	2.6	20	5	2	980(e)	2	
	Basal Blairmore	5.9	10	5	5	980(e)	5	
	Devonian Associated and Solution	7.5(i) 6.6(ii)	35	25	3	1350	4	(i) Original (ii) Less 0.9 Bcf produced to Dec. 31, 1957.

TABLE A - 1 (Continued)

(1) FIELD OR AREA	(2) ZONE	(3) ESTIMATED ORIGINAL GAS IN PLACE BCF	(4) RESERVOIR LOSS DISCOUNT PER CENT	(5) SURFACE LOSS DISCOUNT PER CENT	(6) DISPOSABLE GAS(3) BCF	(7) HEATING VALUE(4) BTU PER CU. FT.	(8) DISPOSABLE GAS (1000 BTU BASIS)(3) BCF	(9) REMARKS
Normandville	Gething	13.2	20	5	10	960	10	
	Triassic	3.7	15	5	3	1070(E)	3	
	Mississippian	23.4	10	5	20	1030	21	
Obed	Rundle	12.3	10	10	10	1020(E)	10	Presently considered beyond economic reach.
Oberlin	Viking	0.6	25	5	0.4	980(E)	0.4	
	Basal Blairmore	1.9(i) 1.0(ii)	20	5	0.6	1070	0.6	(i) Original (ii) Less 0.9 Bcf produced to Dec. 31, 1957. Supplies local utility.
Okotoks	Wabamun	375.2	10	60(i)	135	980	132	(i) High loss due to very high acid gas content.
Olds	Wabamun	139.0	10	20	100	1030	103	
Oyen	Viking	15.8	20	5	12	980	12	
Paddle River	Jurassic	26.3	20	5	20	1050(E)	21	
	Mississippian	3.9	20	5	3	1040(E)	3	
Panther River	Nisku	185.1	10	40	100	1160(E)	116	
Parkland	Rundle	26.2	10	15	20	990	20	
Pembina	Belly River	18.9(i) 18.6(ii)	15	5	15	1160	17	(i) Original (ii) Less 0.3 Bcf produced to Dec. 31, 1957.
	Cardium Solution	1831.0(i) 1764.8(ii)	60	40	400	1150	460	(i) Original (ii) Less 66.2 Bcf produced to Dec. 31, 1957.
	Basal Blairmore	2.8	25	5	2	1290	3	
	Rundle	3.9	15	10	3	1110	3	
Pendant d'Oreille	Bow Island	214.2(i) 169.4(ii)	20	5	120	920	110	(i) Original (ii) Less 44.8 Bcf produced to Dec. 31, 1957.
Phil Can	Gething	11.8	20	5	9	960(E)	9	Presently considered beyond economic reach.
	Mississippian	5.0	15	5	4	1030(E)	4	
Pigeon Lake	Leduc	13.1	10	15	10	1100(E)	11	

TABLE A - 1 (Continued)

(1) FIELD OR AREA	(2) ZONE	(3) ESTIMATED ORIGINAL GAS IN PLACE BCF	(4) RESERVOIR LOSS DISCOUNT PER CENT	(5) SURFACE LOSS DISCOUNT PER CENT	(6) DISPOSABLE GAS(3) BCF	(7) HEATING VALUE(4) BTU PER CU. FT.	(8) DISPOSABLE GAS (1000 BTU BASIS)(3) BCF	(9) REMARKS
Pincher Creek	Rundle	2641.0(i) 2635.0(ii)	14	25	1700	1060	1800	(i) Original (ii) Less 14.7 Bcf produced to Dec. 31, 1957. Injected 8.7 Bcf to Dec. 31, 1957. Net production 6.0 Bcf.
Pine Creek	Wabamun	3.0	10	25	2	1050(e)	2	
	Leduc	555.8	10	40	300	970	291	
Pouce Coupe	Cadotte	194.0(i) 187.9(ii)	10	5	160	980	157	(i) Original (ii) Less 6.1 Bcf produced to Dec. 31, 1957.
	Cadomin	12.4	15	5	10	1040(e)	10	
Pouce Coupe South	Doe Creek	7.0	25	5	5	930	5	
	Cadotte	88.5(i) 82.6(ii)	10	5	70	1020	71	(i) Original (ii) Less 5.9 Bcf produced to Dec. 31, 1957.
	Cadomin	21.1	10	5	18	1040(e)	19	
	Triassic	12.4	15	5	10	1070(e)	11	
Princess	Bow Island	6.6	20	5	5	1020	5	
	Basal Colorado	39.4	20	5	30	1000	30	
	Basal Blairmore	161.0	15	5	130	1010	131	
	Rundle Associated	6.6	20	5	5	1030	5	
	Jefferson Associated	41.2	20	15	28	1010	28	
Provost	Viking	700.0(i) 698.1(ii)	20	5	530	1020	541	(i) Original (ii) Less 1.9 Bcf produced to Dec. 31, 1957.
	Blairmore	12.4	15	5	10	1030	10	
Redwater	Viking	14.7(i) 14.2(ii)	25	5	10	1020	10	(i) Original (ii) Less 0.5 Bcf produced to Dec. 31, 1957.
	Leduc Solution	169.6(i) 139.8(ii)	40	50	36	1250	45	(i) Original (ii) Less 29.8 Bcf produced to Dec. 31, 1957.
Rochester	Viking	5.3	20	5	4	980(e)	4	Presently considered beyond economic reach.
	Blairmore	26.7	25	5	19	980	19	
	Wabamun	5.8	10	5	5	1050(e)	5	
Rolling Hills	Bow Island	26.0	15	5	21	950(e)	20	
	Basal Colorado	7.4	15	5	6	1010(e)	6	

TABLE A - 1 (Continued)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Field or Area	Zone	Estimated Original Gas in Place BCF	Reservoir Loss Discount Per Cent	Surface Loss Discount Per Cent	Disposable Gas(3) BCF	Heating Value(4) BTU per Cu. Ft.	Disposable Gas (1000 BTU Basis)(3) BCF	Remarks
Rosebud	Viking	19.8	20	5	15	980(E)	15	
	Blairmore	24.8	15	5	20	1110	22	
Rosedale	Viking	9.2	20	5	7	980(E)	7	
	Blairmore	20.5(i) 19.9(ii)	15	5	16	1070	17	Supplies local utility. (i) Original (ii) Less 0.6 Bcf produced to Dec. 31, 1957.
Round Valley	Blairmore	24.7	10	10	20	1000(E)	20	
Rycroft	Gething Associated and Non-Associated	15.9(i) 14.0(ii)	15	5	11	1020	11	Supplies local utility. (i) Original (ii) Less 1.9 Bcf produced to Dec. 31, 1957.
St. Albert	Viking	2.6	20	5	2	1010	2	
	Lower Cretaceous	42.1(i) 26.3(ii)	10	5	21	1090	23	(i) Original (ii) Less 15.8 Bcf produced to Dec. 31, 1957.
St. Paul	Blairmore	2.7(i) 1.2(ii)	20	5	0.6	990	0.6	Supplies local utility. (i) Original (ii) Less 1.5 Bcf produced to Dec. 31, 1957.
Saddle Hills	Peace River	26.9	10	5	23	1000	23	Presently considered beyond economic reach.
	Gething	2.6	20	5	2	960(E)	2	
Samson	Basal Blairmore Associated and Non-Associated	16.2(i) 15.5(ii)	20	10	11	1020	11	(i) Original (ii) Less 0.7 Bcf produced to Dec. 31, 1957.
Sarcee	Rundle	138.9	10	20	100	1030	103	
Savanna Creek	Rundle	815.0	10	25	550	980	539	
Sibbald	Viking	46.1	20	5	35	1010	35	
	Blairmore	5.3	20	5	4	970	4	
Smith Coulee	Bow Island	45.0(i) 43.7(ii)	20	5	33	910	30	(i) Original (ii) Less 1.3 Bcf produced to Dec. 31, 1957.

TABLE A - 1 (Continued)

(1) FIELD OR AREA	(2) ZONE	(3) ESTIMATED ORIGINAL GAS IN PLACE BCF	(4) RESERVOIR LOSS DISCOUNT PER CENT	(5) SURFACE LOSS DISCOUNT PER CENT	(6) DISPOSABLE GAS(3) BCF	(7) HEATING VALUE(4) BTU PER CU. FT.	(8) DISPOSABLE GAS (1000 BTU BASIS)(3) BCF	(9) REMARKS
Stettler	Viking	4.2	25	5	3	1000(E)	3	
	Nisku Solution	26.6(i) 24.7(ii)	45	45	7	1110	8	(i) Original (ii) Less 1.9 Bcf produced to Dec. 31, 1957.
	Leduc Solution	11.5(i) 10.6(ii)	45	45	3	1120	3	(i) Original (ii) Less 0.9 Bcf produced to Dec. 31, 1957.
Stolberg	Rundle	86.4	10	10	70	1020	71	Presently considered beyond economic reach.
Sturgeon Lake	Leduc Solution	42.7(i) 41.7(ii)	40	35	16	1050	17	Presently considered beyond economic reach. (i) Original (ii) Less 1.0 Bcf produced to Dec. 31, 1957.
Sturgeon Lake South	Gething	16.1	15	5	13	980(E)	13	
	Cadomin	11.1	15	5	9	1040(E)	9	
	Triassic Non-Associated	3.5	10	5	3	1160	3	
	Triassic Solution	18.6(i) 18.5(ii)	35	25	9	1160	10	(i) Original (ii) Less 0.1 Bcf produced to Dec. 31, 1957.
	Wabamun	7.4	10	25	5	1050(E)	5	
	Leduc Associated	7.4	10	25	5	1060	5	
	Leduc Solution	242.7(i) 238.7(ii)	35	35	100	1060	106	(i) Original (ii) Less 4.0 Bcf produced to Dec. 31, 1957.
Sturgeon Lake South General Area	Gething	61.9	15	5	50	980(E)	49	Presently considered beyond economic reach.
	Triassic	6.2	15	5	5	1160(E)	6	
	Permo-Penn	2.6	20	5	2	1010(E)	2	
Suffield	Milk River	45.0(i) 42.9(ii)	25	5	30	960	29	Supplies local utility. (i) Original (ii) Less 2.1 Bcf produced to Dec. 31, 1957.
Sundre	Mississippian Associated	26.2	10	15	20	1050(E)	21	
	Mississippian Solution	65.2(i) 63.6(ii)	40	20	30	1080	32	(i) Original (ii) Less 1.6 Bcf produced to Dec. 31, 1957.
Sylvan Lake	Basal Blairmore	49.3	10	10	40	1080	43	
	Mississippian	11.1	20	10	8	1080	9	
	Devonian Associated	5.6	10	20	4	1100(E)	4	

TABLE A - 1 (Continued)

(1) FIELD OR AREA	(2) ZONE	(3) ESTIMATED ORIGINAL GAS IN PLACE BCF	(4) RESERVOIR LOSS DISCOUNT PER CENT	(5) SURFACE LOSS DISCOUNT PER CENT	(6) DISPOSABLE GAS(3) BCF	(7) HEATING VALUE(4) BTU PER CU. FT.	(8) DISPOSABLE GAS (1000 BTU BASIS)(3) BCF	(9) REMARKS
Tangent	Cadotte	15.0	30(i)	5	10	990	10	(i) High loss due to low reservoir pressure.
	Gething Triassic	130.1 65.8	15 20	5 5	105 50	980(e) 1160(e)	103 58	
Three Hills Creek	Belly River Viking Mississippian	6.2 6.6 30.9	15 20 10	5 5 10	5 5 25	950(e) 980(e) 1140	5 5 29	
Turin	Bow Island Basal Blairmore Ellis Rundle	5.0 21.1 5.0 2.8	15 10 15 10	5 5 5 20	4 18 4 2	950(e) 1000 1050(e) 1030(e)	4 18 4 2	
Turner Valley	Rundle Associated	-	-	20	200(i)	1100	220	(i) After deducting production to Dec. 31, 1957.
	Rundle Solution	-	-	38	140(i)	1130	158	(i) After deducting production to Dec. 31, 1957.
Two Creek	Triassic	11.7	10	5	10	1070(e)	11	Presently considered beyond economic reach.
Usona	Lower Cretaceous	11.7	10	5	10	1090	11	Presently considered beyond economic reach.
Viking-Kinsella	Viking	983.0(i) 688.1(ii)	25	5	420	970	407	(i) Original (ii) Less 294.9 Bcf produced to Dec. 31, 1957.
	Blairmore	19.8(i) 18.7(ii)	15	5	15	980	15	(i) Original (ii) Less 1.1 Bcf produced to Dec. 31, 1957.
	Devonian	5.3	20	5	4	990	4	
Wainwright	Blairmore	15.6(i) 13.6(ii)	20	5	10	920	9	(i) Original (ii) Less 2.0 Bcf produced to Dec. 31, 1957.
Warburg	Basal Belly River	3.5	10	5	3	1060	3	Presently considered beyond economic reach.
	Viking	10.5	10	5	9	1160	10	
Waterton	Rundle	1667.0	10	50(i)	750	990	742	(i) High loss due to very high acid gas content.

TABLE A - 1 (Continued)

(1) FIELD OR AREA	(2) ZONE	(3) ESTIMATED ORIGINAL GAS IN PLACE BCF	(4) RESERVOIR LOSS DISCOUNT PER CENT	(5) SURFACE LOSS DISCOUNT PER CENT	(6) DISPOSABLE GAS(3) BCF	(7) HEATING VALUE(4) BTU PER CU. FT.	(8) DISPOSABLE GAS (1000 BTU BASIS)(3) BCF	(9) REMARKS
Watts	Viking	1.8(i) 1.4(ii)	20	5	1	1020	1	Supplies local utility. (i) Original (ii) Less 0.4 Bcf produced to Dec. 31, 1957.
	Mississippian	1.3	20	5	1	1050(e)	1	
Wayne	Viking	13.2	20	5	10	980(e)	10	
	Basal Blairmore Associated	13.6	10	10	11	1030	11	
	Basal Blairmore Solution	25.7(i) 25.5(ii)	35	15	14	1040	15	Presently considered beyond economic reach. (i) Original (ii) Less 0.2 Bcf produced to Dec. 31, 1957.
West Drumheller	Basal Blairmore	12.4	15	5	10	1120	11	
	Nisku Associated	9.1	10	15	7	1160(e)	8	
	Nisku Solution	32.2(i) 29.2(ii)	45	25	11	1070	12	(i) Original (ii) Less 3.0 Bcf produced to Dec. 31, 1957.
	Leduc Solution	2.6(i) 2.4(ii)	40	25	1	1100	1	(i) Original (ii) Less 0.2 Bcf produced to Dec. 31, 1957.
Westerose	Leduc Associated	125.0	10	20	90	1050(e)	95	
	Leduc Solution	119.0(i) 115.6(ii)	30	25	60	1080	65	(i) Original (ii) Less 6.0 Bcf produced to Dec. 31, 1957. Injected 2.6 Bcf to Dec. 31, 1957. Net production 3.4 Bcf.
Westerose South	Leduc	1438.0	10	15	1100	1070	1178	
Westlock	Viking	248.8(i) 247.7(ii)	15	5	200	1020	204	Supplies local utility. (i) Original (ii) Less 1.1 Bcf produced to Dec. 31, 1957.
	Basal Blairmore	2.6	20	5	2	1100(e)	2	
West Prairie	Cadotte	17.5	10	5	15	1020(e)	15	Presently considered beyond economic reach.
	Bluesky	5.9	10	5	5	970	5	
Westward Ho	Mississippian Non-Associated	39.2	10	15	30	1050	31	
	Mississippian Solution	34.7(i) 33.5(ii)	35	25	16	1110	18	(i) Original (ii) Less 1.2 Bcf produced to Dec. 31, 1957.

TABLE A - 1 (Continued)

(1) Field or Area	(2) Zone	(3) Estimated Original Gas in Place BCF	(4) Reservoir Loss Discount Per Cent	(5) Surface Loss Discount Per Cent	(6) Disposable Gas(3) BCF	(7) Heating Value(4) BTU per Cu. Ft.	(8) Disposable Gas (1000 BTU Basis)(3) BCF	(9) Remarks
Whitelaw	Gething	39.0(i) 37.5(ii)	15	5	30	1000	30	Supplies local utility. (i) Original (ii) Less 1.5 Bcf produced to Dec. 31, 1957.
	Triassic	32.9	20	5	25	1070(E)	27	
Wildmere	Blairmore	13.4(i) 7.0(ii)	20	5	4.1	940	3.9	Supplies local utility. (i) Original (ii) Less 6.4 Bcf produced to Dec. 31, 1957.
Wildunn Creek	Viking	19.7	20	5	15	990	15	
Wimborne	Viking	1.4	25	5	1	1000(E)	1	
	Nisku Associated	2.8	15	15	2	1160(E)	2	
	Leduc Associated	252.0	10	25	170	920	156	
	Leduc Solution	38.8(i) 38.6(ii)	35	60(iii)	10	1000(E)	10	(i) Original (ii) Less 0.2 Bcf produced to Dec. 31, 1957. (iii) High loss due to very high acid gas content.
Windfall	Viking	4.2	25	5	3	1010(E)	3	
	Leduc Associated and Solution	507.5	10	30	320	1040	333	
Wizard Lake	Viking	2.5	15	5	2	1050(E)	2	
	Basal Blairmore	9.4	10	5	8	1100	9	
	Leduc Solution	212.5(i) 199.3(ii)	40	30	80	1230	98	(i) Original (ii) Less 13.2 Bcf produced to Dec. 31, 1957.
Wood River	Basal Blairmore	46.8	10	5	40	1130	45	
Other reserves less than 10 billion cubic feet not listed above					243.5		243.5	Estimated to be within economic reach.
Other reserves less than 10 billion cubic feet not listed above					581.0		581.0	Presently considered beyond economic reach.
				TOTALS	22,478.4		23,255.1	

TABLE A - 1 (CONTINUED)

GENERAL NOTES.

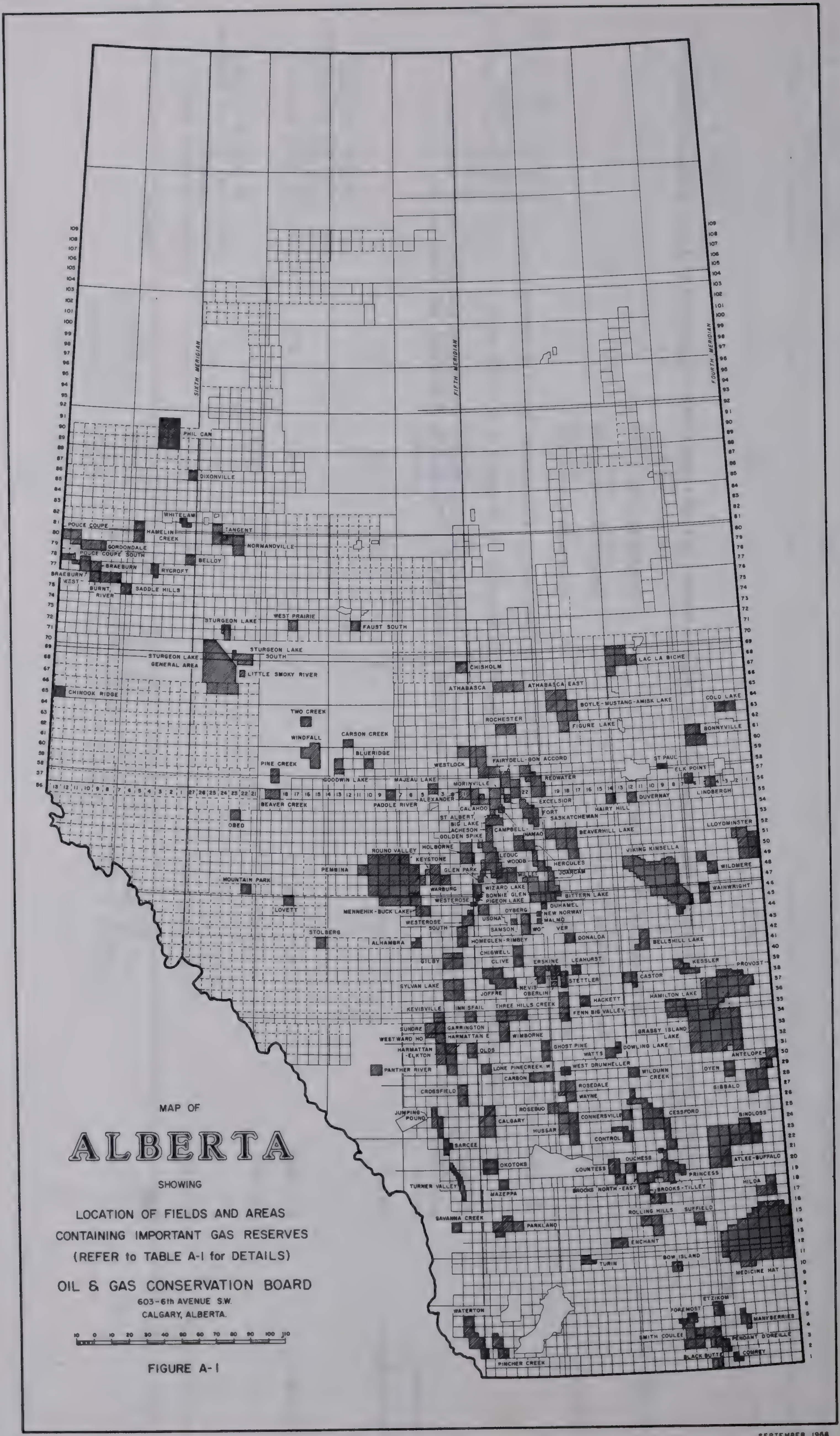
1. UNLESS OTHERWISE NOTED RESERVOIR LOSS IS CALCULATED AS 10% OF ORIGINAL GAS IN PLACE EXCEPT IN PARTICULAR CASES WHERE THE FOLLOWING LOSSES PERTAIN:

SAND THICKNESS 10 - 15 FEET	RESERVOIR LOSS - 15%
SAND THICKNESS 5 - 10 FEET	RESERVOIR LOSS - 20%
SAND THICKNESS 0 - 5 FEET	RESERVOIR LOSS - 25%

2. SURFACE LOSSES TAKEN AS 5% FOR ALL DRY GAS, AND VARIES FOR WET AND SOUR GAS DEPENDING UPON ITS COMPOSITION.

3. THE DISPOSABLE RESERVES AS AT MARCH 31ST, 1958 WITH PRODUCTION DEDUCTED TO DECEMBER 31ST, 1957 ONLY.

4. HEATING VALUE IS HIGHER HEATING VALUE BASED ON AVAILABLE GAS ANALYSES AND ADJUSTED FOR PROCESSING SHRINKAGE WHERE REQUIRED. WHERE NO ANALYSES ARE AVAILABLE BTU VALUES HAVE BEEN BASED ON ANALYSES OF SIMILAR TYPE RESERVOIRS AND SHOWN AS (E).



MAP OF

ALBERTA

SHOWING

LOCATION OF FIELDS AND AREAS
CONTAINING IMPORTANT GAS RESERVES
(REFER to TABLE A-1 for DETAILS)

OIL & GAS CONSERVATION BOARD
603-6th AVENUE S.W.
CALGARY, ALBERTA.

FIGURE A-1

APPENDIX B

THE TRENDS IN EXPLORATION FOR AND THE GROWTH OF RESERVES OF GAS IN ALBERTA

There are two general methods which have been used by estimators in forecasting the development of reserves of oil or gas; the geological method and the statistical method. Each method will be reviewed in so far as it relates to the growth of reserves of natural gas in the Province of Alberta.

While reserves published in this report have been converted to 1,000 Btu equivalent basis, due to the large amount of historical data used in development of the trends for this Appendix, reserves on an actual Btu or unconverted basis have been used. In view of the slight difference in total provincial reserves on the 1,000 Btu equivalent and on the unconverted basis, the Board believes that the trend data may be used in its present form for predicting future established reserves of gas having an average heating value of 1,000 Btu per standard cubic foot.

Forecast Based on Geological Method

The geological method consists of determining the volume of available sediments and applying known factors with respect to the accumulation of crude oil reserves in relation to the volume of sediments in the United States and the ratio of established gas reserves to established oil reserves. The method was discussed fully in a submission made by the Board's staff to the Royal Commission on Canada's Economic Prospects in October, 1955. In the submission the Board's staff estimated that there existed within the Alberta portion of the Western Canada Sedimentary Basin a maximum area of 213,500 square miles of land favorable for the prospecting for crude petroleum and natural gas. This figure included all of the area covered by sediments to a depth in excess of 1,000 feet but did not include the mountain ranges. The volume of sediments occurring between the base of the glacial drift and the top of the precambrian granite over the available acreage of sediments underlying the plains area of Alberta has been calculated to be approximately 225,000 cubic miles. By assigning a uniform thickness of 20,000 feet to the entire foothills belt (presently considered to represent the economic depth limit for future exploration in the foothills), an additional 45,000 cubic miles of effective basin sediments have been calculated to exist in Alberta. In previous Board reports it has been assumed that the area of potential gas lands in the Province is 200,000 square miles. As a conservative estimate the latter figure again will be used for this report.

At the hearing before the Royal Commission on Energy, held from February to May, 1958, submissions were made by the Canadian Petroleum Association, Shell Oil Company of Canada, Limited and this Board in which the geological method of estimating the cumulative initial recoverable gas reserves for the Province of Alberta was used. The Board's submission indicated that Alberta contained some 270,000 cubic miles of sediments favorable for the accumulation of oil and gas. By applying a minimum and maximum accumulation factor of

40,000 and 55,000 barrels of oil per cubic mile of sediments and the ratio of established gas reserves to established oil reserves at December 31st, 1957, of 5,500 cubic feet per barrel, one obtains the corresponding range of cumulative initial recoverable gas reserves of 60 to 83 trillion cubic feet. The Canadian Petroleum Association brief contained estimates as follows:

(a) 340,000 cubic miles of available sediments in Alberta.

(b) Accumulation of crude oil reserves in relation to the volume of sediments of 30,000 barrels per cubic mile to 50,000 barrels per cubic mile.

(c) The ratio of established initial disposable gas reserves to initial recoverable crude oil reserves of 6,000 cubic feet per barrel.

The application of these factors gives a range of cumulative initial recoverable gas reserves of 61 to 102 trillion cubic feet. While the Shell Oil Company of Canada, Limited exhibit did not present the data in a manner such that an estimate could be obtained for the Province of Alberta, the data presented for the Western Canada Sedimentary Basin as a whole was in substantial agreement with that presented in the Canadian Petroleum Association brief.

Forecast Based on Statistical Method

The statistical method of estimating the growth of reserves of natural gas in the Province has been used in four previous Board reports. In this report the method is again employed but in an extended form. Data dealing with the number of wildcat wells drilled and the initial disposable gas reserves discovered to March 31st, 1958, are presented in Tables B-1 and B-2. These data show that as at March 31st, 1958, the drilling of 4,198 wildcat wells had resulted in the discovery of some 23.7 trillion cubic feet of initial disposable gas reserves. The density of wildcat drilling as at that date was one wildcat well per 48 square miles (of the 200,000 square miles of potential gas area) and the drilling of these wells resulted in an overall discovery rate of 5.7 billion cubic feet of gas for every wildcat well drilled. The corresponding rates established to June, 1955, and to September, 1956, were respectively 5.4 and 5.6 billion cubic feet of gas per wildcat well.

Time Lag in Evaluation of Reserves

Using the data listed in Table B-1 a plot of the growth of the cumulative initial disposable reserves of natural gas by years has been made and is shown in Figure B-1. Also shown are the corresponding curves published in Board reports of March, 1952, November, 1953, November, 1955, and January, 1957. The Board concluded in previous reports that a time lag of several years occurs before new discoveries may be fully evaluated. The curve of the most recent data shown in Figure B-1 confirms this previous conclusion. Furthermore, the Board now believes that there is a sufficient number of curves on Figure B-1 that quantitative analysis of the time lag effect can be made.

The amount by which reserves, established as at December 31st, 1951, and represented by the lowermost curve in Figure B-1 had increased at the dates of subsequent reserve estimations was determined from Figure B-1. In Table B-3 are shown the reserves of December 31st, 1951, as estimated in the March, 1952, report and as shown in subsequent reports effective June 30th, 1953, June 30th, 1955, September 30th, 1956, and March 31st, 1958. It may be seen that the reserves increased from 7.4 trillion cubic feet to 11.6 trillion cubic feet. Columns 4 and 5 show respectively the cumulative increase in reserves between estimates and the elapsed time from the original estimate. The reserve estimates as of June 30th, 1953, June 30th, 1955, and September 30th, 1956, have been treated in a similar manner. The data tabulated in Table B-3 have been plotted in Figure B-2 and a curve has been drawn through the points using the method of least squares. The curve indicates that an estimate of the cumulative initial disposable reserves for the Province of Alberta as of any particular date can be expected to increase by 2 trillion cubic feet when re-evaluated one year later. Similarly, the estimate will have increased by 4 trillion cubic feet when reviewed 4½ years after the date of the original estimate and by about 4.5 trillion cubic feet when finally fully assessed.

Figure B-3 treats the data of Table B-3 in a slightly different manner by showing the increase in reserves which may be expected to be added to any particular reserve estimate when completely assessed at a future date. The curve shows, for example, that a reserve estimate made today will be increased by 4½ trillion cubic feet when the fields and areas contained in the estimate have been fully evaluated in the future. Similarly, an estimate of reserves made one year ago, which will have increased through development by 2 trillion cubic feet when re-evaluated this year will be further increased by 2½ trillion cubic feet when fully evaluated in the future. The curve of Figure B-3 has been used to construct Table B-4 and to adjust the curves of Figures B-4, B-8 and B-9 to correct for the amount of under-estimation indicated to be present in the Board's more recent reserve estimates. Figure B-3 has been extrapolated beyond 10 years at a constant value of approximately 200 billion cubic feet per year to account for continuing development in several early discoveries, principally in the Medicine Hat Field.

Growth in Reserves with Wildcat Drilling - Provincial Basis

Figure B-4 shows the initial disposable reserves per wildcat well established for the years 1943 to 1958 inclusive on an annual and cumulative basis as tabulated in Table B-2. The dashed line A-A indicates the ratio of the initial disposable reserves discovered per year to the number of wildcat wells drilled per year. It is erratic due to its sensitivity to discoveries of larger reserves. Recognizing that the reserves established for the more recent years have not been fully evaluated the curve of Figure B-3 was used to adjust upward the data for the years 1951 to 1958. This has resulted in the dashed line A^1-A^1.

The line B-B is the ratio of the cumulative initial disposable reserves discovered to the cumulative number of wildcat wells drilled. In a similar manner the curve B-B has been adjusted for the time lag effect resulting in the curve $B^1 - B^1$. The curve B-B indicates that as at March, 1958, due to the drilling of 4,198 wildcat wells which resulted in the discovery of some 23.7 trillion cubic feet of initial disposable gas reserves, the cumulative rate of discovery was 5.7 billion cubic feet for each wildcat well drilled. When adjustments have been made for the degree of under-estimation of established reserves for the years 1951 to 1958 inclusive, the cumulative rate of discovery is shown by curve $B^1 - B^1$ to be 6.7 billion cubic feet for each wildcat well drilled. The Board believes that six billion cubic feet, its previous interpretation of the reserves which may be developed per wildcat well drilled is a sound and conservative estimate at the present time.

Growth in Reserves with Wildcat Drilling - Regional Basis

The trends in initial disposable reserves per wildcat well drilled were developed for the Eastern, Central, Foothills and Northern areas of the Province. The boundaries of these areas are shown in Figure B-5. It should be noted that the Rocky Mountain area, with the exception of a narrow belt along the eastern edge to include such discoveries as Savanna Creek, has been excluded from the area of available sediments. Well completion data for the six-year period, 1952 to 1957, were reviewed to obtain the number of exploratory wells drilled in each area per year. The initial disposable reserves discovered during this period, as currently estimated, were similarly broken down by areas. The corresponding initial disposable reserves per wildcat well drilled were calculated for each area on both an annual and cumulative basis. These data are presented in Table B-5.

The cumulative initial disposable reserves per wildcat well by areas, extrapolated to 1980, are shown in Figure B-7. The annual disposable reserves per wildcat are very sensitive to large discoveries, particularly in the Foothills Area, and are not presented graphically. An assumption was first made that the presently established reserves per wildcat well for each area would continue at the same rate in the future. As later explained, this was considered to be too optimistic and the rates for the Foothills and Central Areas were adjusted downward for future years. The rates for the Eastern and Northern Areas are relatively small and were extrapolated without adjustment.

Forecast of Drilling Activity

Figure B-6 shows both the numbers of wildcat wells drilled per year by areas of the Province for the past seven years and an extrapolation of the trends into the future. In forecasting the trends it was assumed that activity in the Foothills and Northern areas would increase, while that in the Eastern area would decrease, leaving the provincial total for the next 15 to 20 years at 400 wells per year. This forecast assumes a proper incentive for exploration.

Overall Growth in Reserves

The relationship of the cumulative initial disposable gas reserves and the cumulative number of wildcat wells drilled is shown in Figure B-8. The upper portions of the curves have been reproduced on a larger scale and are presented as Figure B-9. The line ABC is the estimate of the growth trend which was presented in the Board's submission to the Royal Commission on Energy in February, 1958, and which was based on well statistics and reserve data to December 31st, 1957. The addition of the corresponding information to March 31st, 1958, has not affected the location of this line.

In order to examine the effect of the under-estimation of the more recent years' reserve estimates as previously discussed, the cumulative initial disposable reserves for the years 1951 to 1958 inclusive were adjusted upward through the use of Figure B-3. The revised data are plotted on Figure B-9 as points enclosed in small triangles. A graph of the relationship of the cumulative initial disposable reserves and the cumulative number of wildcat wells drilled using adjusted data for the years 1951 to 1958 is shown as Line DEF.

The effect of applying the results of the study of the geographical distribution of the exploration data shown in Table B-5 and Figures B-5, B-6 and B-7 was examined. Initially it was assumed that the reserves established in each area per wildcat well drilled in the area at the present time would remain the same in the future. A cumulation of the products of the area values shown in Figures B-6 and B-7 when plotted on Figures B-8 and B-9 resulted in curve DEG. This curve indicates a long term expanding rate of increase in the establishment of cumulative initial disposable reserves. This may be possible but, in the Board's opinion, cannot be counted upon. The rates for the Foothills and Central Areas were therefore adjusted to reflect a decline in the future rate of establishment of reserves per wildcat well drilled as shown in Figure B-7. Plotting the revised data on Figures B-8 and B-9 gives curve DEH. This curve indicates a short term expanding rate of increase through the drilling of an additional four thousand wildcat wells and a declining rate thereafter. It should be noted that lines DEG and DEH are based on the curves of Figures B-6 and B-7 which have been projected to 1980 or to the drilling of some 13,000 wildcat wells. Line DEH has then been merely extrapolated to the drilling of 20,000 wildcat wells.

The projection shows that upon the drilling of 20,000 wildcat wells or an average of one per ten square miles of the potential sedimentary area in Alberta, cumulative initial disposable reserves of 85 trillion cubic feet may be expected. The Board considers the extrapolation shown by line DEH to be realistic.

From the projection of line DEH of Figure B-9 and the Figure B-6 it is readily possible to construct a tabulation of the estimated future reserves by years. Such a tabulation was prepared for the period 1958 to 1987 inclusive. The tabulation showed a growth in initial cumulative established reserves from 28.3 to 79.0 trillion cubic feet. Recognizing that the time lag effect has been eliminated in the projection, this is equivalent to a growth of actual initial established reserves from 23.8 to 74.5 trillion cubic feet, representing future reserves of some 51 trillion cubic feet. These new reserves are expected to be discovered over the period 1958 to 1987 assuming only a proper incentive for exploration and the drilling of the required number of wildcat wells.

TABLE B - 1

OIL AND GAS CONSERVATION BOARD

TRENDS IN WILDCAT DRILLING AND GROWTH OF DISPOSABLE GAS RESERVES IN THE PROVINCE OF ALBERTA

1	2	3	4	5	6	7	8
YEAR	WILDCAT WELLS PER YEAR	WILDCAT WELLS CUMULATIVE	NAME OF FIELD DISCOVERED	REMAINING DISPOSABLE GAS RESERVES AS OF MARCH 31, 1958 BCF	SALES TO DEC. 31, 1957 BCF	INITIAL DISPOSABLE GAS RESERVES AT DATE OF DISCOVERY BCF	CUMULATIVE INITIAL DISPOSABLE GAS RESERVES AT DATE OF DISCOVERY BCF
Prior to 1930		172	Medicine Hat (Medicine Hat), Bow Island, Brooks-Tilley, Viking-Kinsella (Viking), Turner Valley, Foremost, Pouce Coupe, Wainwright	2355	916	3271	3271
1930	29	201					3271
1931	9	210					3271
1932	6	216	Pinhorn	3	-	3	3274
1933	7	223					3274
1934	3	226	Lloydminster	5	8	13	3287
1935	2	228					3287
1936	8	236					3287
1937	15	251	Wildmere	4	6	10	3297
1938	12	263					3297
1939	18	281					3297
1940	23	304	Princess	188	-	188	3485
1941	20	324	Suffield	30	2	32	3517
1942	43	367	Oyen	12	-	12	
			Other Small Fields	8	-	8	3537
1943	34	401	Athabasca (Lower Cretaceous)	3	1	4	3541
1944	56	457	Black Butte	31	9	40	
			Jumping Pound	515	73	588	4169
1945	56	513	Patricia	10	-	10	
			Other Small Fields	4	-	4	4183

TABLE B - 1

1	2	3	4	5	6	7	8
YEAR	WILDCAT WELLS PER YEAR	WILDCAT WELLS CUMULATIVE	NAME OF FIELD DISCOVERED	REMAINING DISPOSABLE GAS RESERVES AS OF March 31, 1958 BCF	SALES TO Dec. 31, 1957 BCF	INITIAL DISPOSABLE GAS RESERVES AT DATE OF DISCOVERY BCF	CUMULATIVE INITIAL DISPOSABLE GAS RESERVES AT DATE OF DISCOVERY BCF
1946	54	567	Beaverhill Lake, (Viking)	100	0	100	
			Brooks North-East (Sunburst)	10	1	11	
			Lindbergh	3	2	5	
			Pendant d'Oreille	120	43	163	
			Provost	540	2	542	5004
1947	71	638	Fairydell-Bon Accord	102	4	106	
			Leduc Woodbend	548	89	637	
			Manyberries	50	3	53	
			Medicine Hat (Bow Island and Ellis)	20	-	20	
			St. Paul	0.6	1.4	2	
			Smith Coulee	33	1	34	
			Other Small Fields	7	-	7	5863
1948	126	764	Brooks North-East (Bow Island)	10	-	10	
			Dowling Lake	0.3	0.3	1	
			Elk Point	0.5	0.4	1	
			Morinville	95	17	112	
			Pincher Creek	1700	-	1700	
			Redwater	46	1	47	
			Other Small Fields	7	-	7	7741
1949	209	973	Bonnyville	2.5	0.8	3	
			Boyle-Mustang-Amisk Lake	20	-	20	
			Calahoo	13	-	13	
			Campbell-Namao	45	-	45	
			Castor	20	-	20	
			Cessford	1070	-	1070	
			Excelsior	44	-	44	
			Golden Spike	104	-	104	
			Joarcam	65	-	65	
			Lac La Biche	45	-	45	
			Normandville (Gething)	10	-	10	
			Oberlin	1	1	2	
			Rochester	28	-	28	
			Stettler	18	-	18	
			Westlock ((Viking)	200	1	201	
			Other Small Fields	53	-	53	9482
1950	224	1197	Acheson	65	1	66	
			Athabasca East	1.2	0.4	2	
			Countess	54	-	54	
			Duhamel	12	-	12	
			Fenn-Big Valley	89	1	90	
			Leahurst	7.1	0.5	8	
			Rolling Hills (Bow Island)	21	-	21	
			Sibbald	39	-	39	
			Turin (Rundle)	2	-	2	
			Whitelaw	55	1	56	
			Other Small Fields	60	-	60	9892

TABLE B - 1

1	2	3	4	5	6	7	8
YEAR	WILDCAT WELLS PER YEAR	WILDCAT WELLS CUMULATIVE	NAME OF FIELD DISCOVERED	REMAINING DISPOSABLE GAS RESERVES AS OF MARCH 31, 1958 BCF	SALES TO DEC. 31, 1957 BCF	INITIAL DISPOSABLE GAS RESERVES AT DATE OF DISCOVERY BCF	CUMULATIVE INITIAL DISPOSABLE GAS RESERVES AT DATE OF DISCOVERY BCF
1951	461	1658	Athabasca (Wabamun)	3	-	3	
			Atlee-Buffalo (Viking)	70	-	70	
			Belloy (Mississippian)	15	-	15	
			Bonnie Glen	580	13	593	
			Clive	16	-	16	
			Duchess	19	-	19	
			Etzikom (Bow Island)	120	4	124	
			Figure Lake	30	-	30	
			Fort Saskatchewan	120	19	139	
			Glen Park	15	1	16	
			Hamelin Creek	43	-	43	
			Harmatton-Elkton (Non-Associated)	55	-	55	
			Hercules	19	-	19	
			Majeau Lake	12	-	12	
			Millet	15	-	15	
			New Norway	10	-	10	
			Okotoks	135	-	135	
			St. Albert	23	15	38	
			Tangent	165	-	165	
			Turin (Bow Island, Basal Blairmore and Ellis)	26	-	26	
			Viking-Kinsella (Blairmore and Devonian)	20	1	21	
			Watts	2	0	2	
			Westlock (Blairmore)	2	-	2	
			Wimborne (Nisku Associated)	2	-	2	
			Wizard Lake	90	5	95	
			Other Small Fields	53	-	53	11,610
1952	469	2127	Belloy (Cadotte and Gething)	54	-	54	
			Big Lake	10	-	10	
			Bindloss (Viking)	280	1	281	
			Bittern Lake	26	-	26	
			Chigwell	30	-	30	
			Cold Lake	2.4	0.8	3	
			Comrey	45	0	45	
			Dixonville	27	-	27	
			Duvernay	0.3	1.2	1	
			Erskine	48	0	48	
			Ghost Pine	15	-	15	
			Gordondale (Cadotte)	50	0	50	
			Hackett	70	-	70	
			Hairy Hill	14	1	15	
			Hamilton Lake	40	-	40	
			Hussar (Blairmore)	160	-	160	
			Malmo	17	-	17	
			Minnehik-Buck Lake	272	-	272	
			Nevis	550	-	550	

TABLE B - 1

1 YEAR	2 WILDCAT WELLS PER YEAR	3 WILDCAT WELLS CUMULATIVE	4 NAME OF FIELD DISCOVERED	5 REMAINING DISPOSABLE GAS RESERVES AS OF MARCH 31, 1958 BCF	6 SALES TO DEC. 31, 1957 BCF	7 INITIAL DISPOSABLE GAS RESERVES AT DATE OF DISCOVERY BCF	8 CUMULATIVE INITIAL DISPOSABLE GAS RESERVES AT DATE OF DISCOVERY BCF
1952 (CONT)			OLDS	100	-	100	
			PHIL CAN	13	-	13	
			PIGEON LAKE	10	-	10	
			RYCROFT	11	2	13	
			STURGEON LAKE	16	-	16	
			STURGEON LAKE SOUTH GENERAL AREA	57	-	57	
			WEST DRUMHELLER	29	-	29	
			WESTEROSE	150	-	150	
			WILDUNN CREEK	15	-	15	
			OTHER SMALL FIELDS	84	-	84	13,811
1953	399	2526	ATLEE-BUFFALO (BASAL BLAIRMORE)	70	-	70	
			DONALDA	14	-	14	
			DYBERG	14	-	14	
			ENCHANT	11	-	11	
			GILBY	234	-	234	
			GORDONDALE (NOTIKEWIN AND GETHING)	83	0	83	
			HARMATTAN-ELKTON (MISSISSIPPIAN ASSOCIATED)	810	-	810	
			HOMEGLEN-RIMBEY	770	-	770	
			JOFFRE (VIKING SOLUTION)	12	-	12	
			KESSLER	50	-	50	
			LITTLE SMOKY RIVER	14	-	14	
			PARKLAND	20	-	20	
			PEMBINA	420	-	420	
			POUCE COUPE SOUTH	103	5	108	
			ROSEDALE	23	1	24	
			SAMSON	11	1	12	
			STURGEON LAKE SOUTH	144	-	144	
			SLYVAN LAKE	52	-	52	
			THREE HILLS CREEK	35	-	35	
			USONA	10	-	10	
			WESTEROSE SOUTH	1100	-	1100	
			WOOD RIVER	40	-	40	
			OTHER SMALL FIELDS	101	-	101	17,959
1954	351	2877	ALEXANDER	35	8	43	
			ALHAMBRA	27	-	27	
			BELLSHILL LAKE	61	-	61	
			BINDLOSS (BASAL BLAIRMORE)	20	-	20	
			BRAEBURN	96	-	96	
			CALGARY (D-1)	480	-	480	
			GARRINGTON	40	-	40	
			CRASSY ISLAND LAKE	20	-	20	
			HARMATTON-ELKTON (MISSISSIPPIAN SOLUTION)	85	-	85	
			HOLBORNE	24	-	24	
			SADDLE HILLS	25	-	25	
			SARCEE	100	-	100	
			SAVANNA CREEK	550	-	550	
			WAYNE	35	-	35	
			WESTWARD HO (RUNDLE-NON ASSOCIATED)	30	-	30	
			WIMBORNE (VIKING AND LEDUC)	181	-	181	
			OTHER SMALL FIELDS	48	-	48	19,824

TABLE B – 1

1 YEAR	2 WILDCAT WELLS PER YEAR	3 WILDCAT WELLS CUMULATIVE	4 NAME OF FIELD DISCOVERED	5 REMAINING DISPOSABLE GAS RESERVES AS OF MARCH 31, 1958 BCF	6 SALES TO DEC. 31, 1957 BCF	7 INITIAL DISPOSABLE GAS RESERVES AT DATE OF DISCOVERY BCF	8 CUMULATIVE INITIAL DISPOSABLE GAS RESERVES AT DATE OF DISCOVERY BCF
1955	346	3223	Burnt River	10	-	10	
			Carbon	223	-	223	
			Control	20	-	20	
			Etzikom (Basal Blairmore	1	-	1	
			Hilda	15	-	15	
			Hussar (Viking and Basal Colorado)	34	-	34	
			Rolling Hills (Basal Colorado)	6	-	6	
			Rosebud	35	-	35	
			Sundre	50	-	50	
			Westward Ho (Rundle Solution)	16	-	16	
			Windfall	323	-	323	
			Other Small Fields	90	-	90	20,647
1956	384	3607	Beaver Creek	20	-	20	
			Beaverhill Lake (Blairmore)	3	-	3	
			Belloy (Notikewin)	7	-	7	
			Braeburn West	88	-	88	
			Chinook Ridge	45	-	45	
			Connorsville	18	-	18	
			Crossfield	180	-	180	
			Goodwin Lake	28	-	28	
			Harmattan East	110	-	110	
			Innisfail	76	-	76	
			Kevisville	10	-	10	
			Mazeppa	15	-	15	
			Mountain Park	25	-	25	
			Normandville (Triassic and Mississippian)	23	-	23	
			Obed	10	-	10	
			Paddle River	23	-	23	
			Two Creek	10	-	10	
			Warburg	12	-	12	
			Waterton	750	-	750	
			West Prairie	20	-	20	
			Other Small Fields	128	-	128	22,248
1957	428	4035	Antelope	12	-	12	
			Blueridge	13	-	13	
			Calgary (Basal Quartz and Elkton)	560	-	560	
			Carson Creek	30	-	30	
			Chisholm	10	-	10	
			Faust South	10	-	10	
			Joffre (Nisku Solution and Basal Blairmore)	55	-	55	
			Keystone	73	-	73	
			Lovett	70	-	70	
			Pine Creek	302	-	302	
			Round Valley	20	-	20	
			Stolberg	70	-	70	
			Other Small Fields	157	-	157	23,630

TABLE B - 1

1 YEAR	2 WILDCAT WELLS PER YEAR	3 WILDCAT WELLS CUMULATIVE	4 NAME OF FIELD DISCOVERED	5 REMAINING DISPOSABLE GAS RESERVES AS OF MARCH 31, 1958 BCF	6 SALES TO DEC. 31, 1957 BCF	7 INITIAL DISPOSABLE GAS RESERVES AT DATE OF DISCOVERY BCF	8 CUMULATIVE INITIAL DISPOSABLE GAS RESERVES AT DATE OF DISCOVERY BCF
1958 (Jan. - March)	163	4198	Lone Pine Creek West	20	-	20	
			Panther River	100	-	100	
			Other Small Fields	15	-	15	23,765

TABLE B - 2

OIL AND GAS CONSERVATION BOARD

TRENDS IN THE GROWTH OF INITIAL DISPOSABLE RESERVES PER WILDCAT WELL DRILLED

1	2	3	4	5	6	7
					INITIAL DISPOSABLE RESERVES PER WILDCAT	
YEAR	WILDCAT WELLS DRILLED	CUMULATIVE WILDCAT WELLS DRILLED	ANNUAL INCREASE IN DISPOSABLE RESERVES BCF	CUMULATIVE DISPOSABLE RESERVES BCF	ANNUAL BASIS BCF	CUMULATIVE BASIS BCF
1942		367		3537		
1943	34	401	4	3541	0.12	8.83
1944	56	457	628	4169	11.21	9.12
1945	56	513	14	4183	0.25	8.15
1946	54	567	821	5004	15.20	8.83
1947	71	638	859	5863	12.10	9.19
1948	126	764	1878	7741	14.90	10.13
1949	209	973	1741	9482	8.33	9.75
1950	224	1197	410	9892	1.83	8.26
1951	461	1658	1718	11610	3.73	7.00
1952	469	2127	2201	13811	4.69	6.49
1953	399	2526	4148	17959	10.40	7.11
1954	351	2877	1865	19824	5.31	6.89
1955	346	3223	823	20647	2.38	6.41
1956	384	3607	1601	22248	4.17	6.17
1957	428	4035	1382	23630	3.23	5.86
1958 (JAN. - MARCH)	163	4198	135	23765	0.83	5.66

TABLE B - 3

OIL AND GAS CONSERVATION BOARD

CUMULATIVE INCREASE IN ESTABLISHED INITIAL DISPOSABLE GAS RESERVES SUBSEQUENT TO ORIGINAL RESERVE ESTIMATE

1 ESTABLISHED RESERVES AS OF	2 DATE OF RESERVE ESTIMATE	3 ESTABLISHED RESERVES(1) BCF	4 CUMULATIVE INCREASE IN RESERVES BCF	5 TIME FROM DATE OF ORIGINAL ESTIMATE YEARS
December 31, 1951	December 31, 1951	7385		
	June 30, 1953	10199	2814	1.5
	June 30, 1955	11572	4187	3.5
	September 30, 1956	11237	3852	4.75
	March 31, 1958	11610	4225	6.25
June 30, 1953	June 30, 1953	11819		
	June 30, 1955	14190	2370	2.0
	September 30, 1956	14740	2920	3.25
	March 31, 1958	15860	4040	4.75
June 30, 1955	June 30, 1955	16146		
	September 30, 1956	18180	2034	1.25
	March 31, 1958	20230	4084	2.75
September 30, 1956	September 30, 1956	19115		
	March 31, 1958	21820	2705	1.5

(1) Figure B - 1

TABLE B - 4

OIL AND GAS CONSERVATION BOARD

CUMULATIVE INITIAL DISPOSABLE RESERVES ADJUSTED TO SHOW ANTICIPATED APPRECIATION OF CURRENT ESTIMATE

1		2	3	4
CURRENT INITIAL DISPOSABLE RESERVES(1)		ELAPSED TIME TO DATE OF CURRENT ESTIMATE	APPRECIATION OF RESERVES(2)	ULTIMATE RESERVES
AS OF	BCF	YEARS	BCF	BCF
December 31, 1950	9892	7.25	200	10090
December 31, 1951	11610	6.25	220	11830
December 31, 1952	13811	5.25	320	14130
December 31, 1953	17959	4.25	560	18520
December 31, 1954	19824	3.25	980	20800
December 31, 1955	20647	2.25	1550	22200
December 31, 1956	22248	1.25	2250	24500
December 31, 1957	23630	0.25	3500	27130
March 31, 1958	23765	0.00	4500	28260

(1) Table B - 1

(2) Figure B - 3

TABLE B - 5

OIL AND GAS CONSERVATION BOARD

TRENDS IN WILDCAT DRILLING AND GROWTH OF DISPOSABLE RESERVES BY AREA

1	2	3	4	5	6	7	8
		ANNUAL BASIS			CUMULATIVE BASIS		
AREA	YEAR	WILDCAT WELLS DRILLED	DISPOSABLE RESERVES DISCOVERED - BCF	DISPOSABLE RESERVES PER WILDCAT - BCF	WILDCAT WELLS DRILLED	DISPOSABLE RESERVES DISCOVERED - BCF	DISPOSABLE RESERVES PER WILDCAT - BCF
Eastern	1952	186	460	2.47	186	460	2.47
	1953	191	169	0.88	377	629	1.67
	1954	131	116	0.89	508	745	1.47
	1955	113	75	0.66	621	820	1.32
	1956	101	40	0.40	722	860	1.19
	1957	128	44	0.34	850	904	1.06
Central	1952	268	1737	6.48	268	1737	6.48
	1953	196	3969	20.22	464	5706	12.30
	1954	209	1099	5.25	673	6805	10.12
	1955	218	748	3.53	891	7553	8.48
	1956	252	758	3.01	1143	8311	7.27
	1957	258	1154	4.47	1401	9465	6.76
Foothills	1952	3	5	1.67	3	5	1.67
	1953	4	0	0	7	5	0.71
	1954	2	650	325	9	655	72.8
	1955	13	0	0	22	655	29.8
	1956	14	796	56.9	36	1451	40.3
	1957	18	170	9.44	54	1621	30.0
Northern	1952	12	0	0	12	0	0
	1953	8	10	1.25	20	10	0.50
	1954	9	0	0	29	10	0.34
	1955	2	0	0	31	10	0.32
	1956	17	7	0.41	48	17	0.35
	1957	24	14	0.58	72	31	0.43
Provincial Total	1952	469	2201	4.70	469	2201	4.70
	1953	399	4148	10.39	868	6349	7.32
	1954	351	1865	5.31	1219	8214	6.75
	1955	346	823	2.38	1565	9037	5.77
	1956	384	1601	4.17	1949	10638	5.46
	1957	428	1382	3.23	2377	12020	5.07

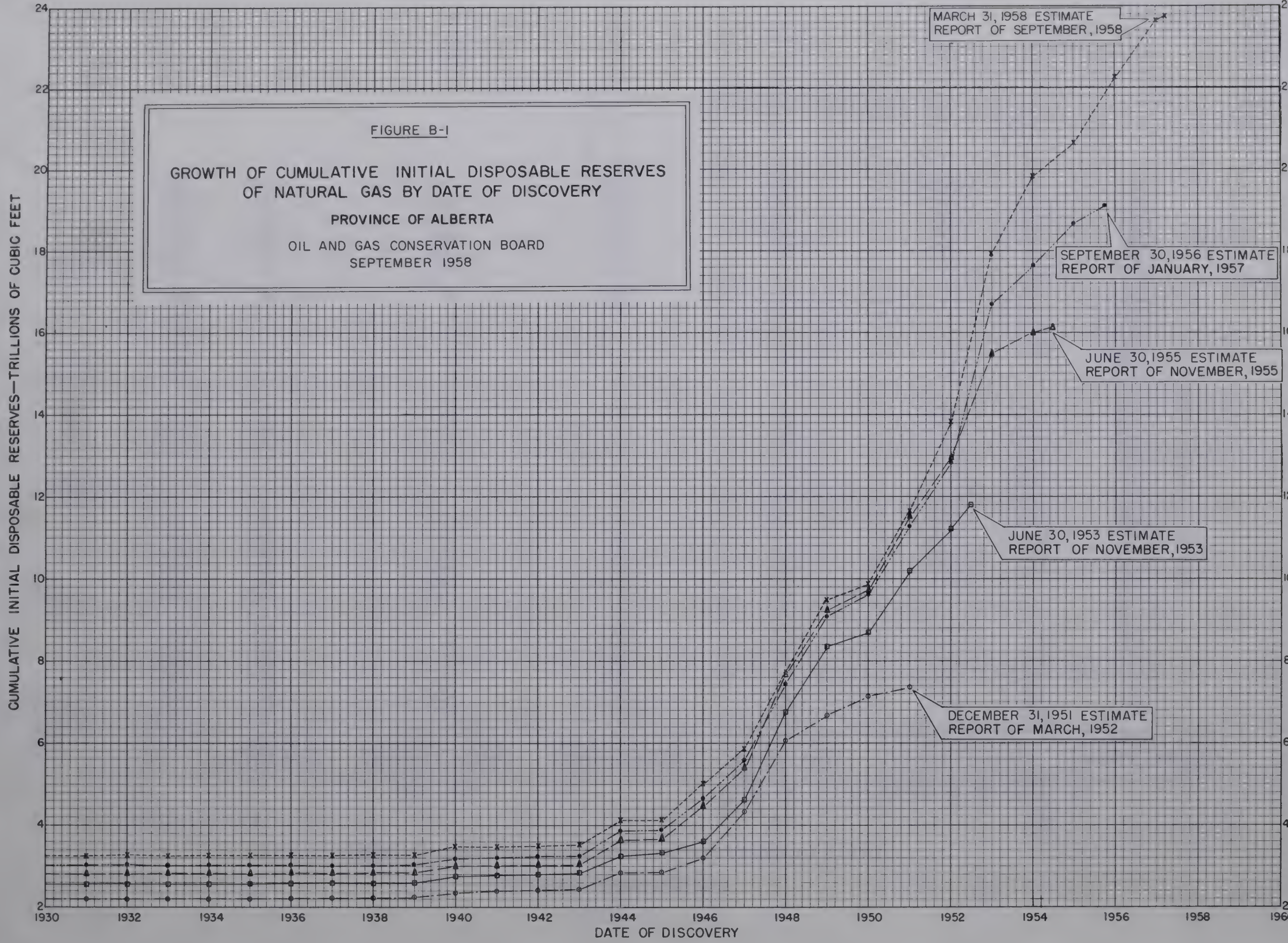


FIGURE B-I

GROWTH OF CUMULATIVE INITIAL DISPOSABLE RESERVES OF NATURAL GAS BY DATE OF DISCOVERY

PROVINCE OF ALBERTA

OIL AND GAS CONSERVATION BOARD
SEPTEMBER 1958

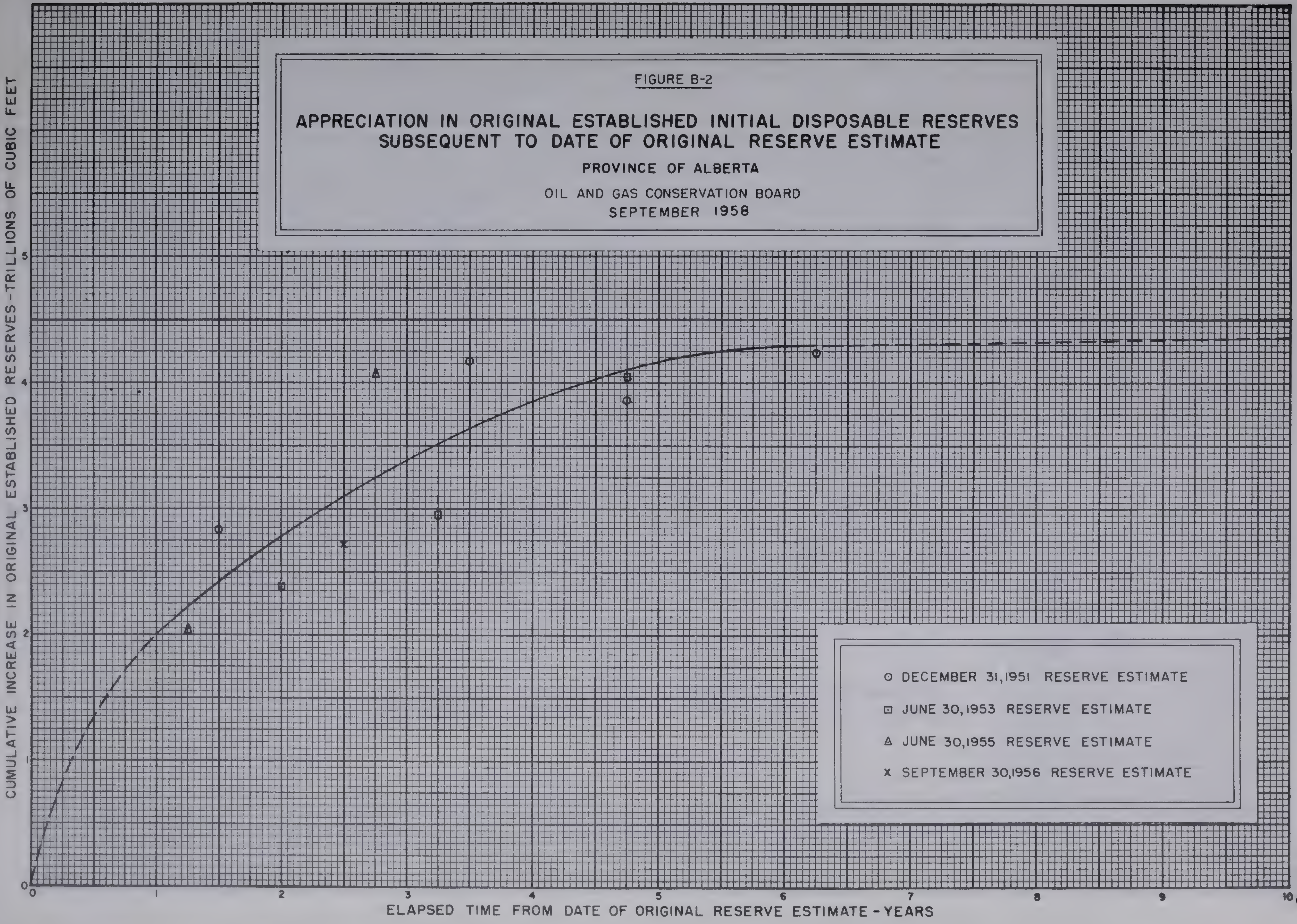


FIGURE B-2

APPRECIATION IN ORIGINAL ESTABLISHED INITIAL DISPOSABLE RESERVES SUBSEQUENT TO DATE OF ORIGINAL RESERVE ESTIMATE

PROVINCE OF ALBERTA

OIL AND GAS CONSERVATION BOARD
SEPTEMBER 1958

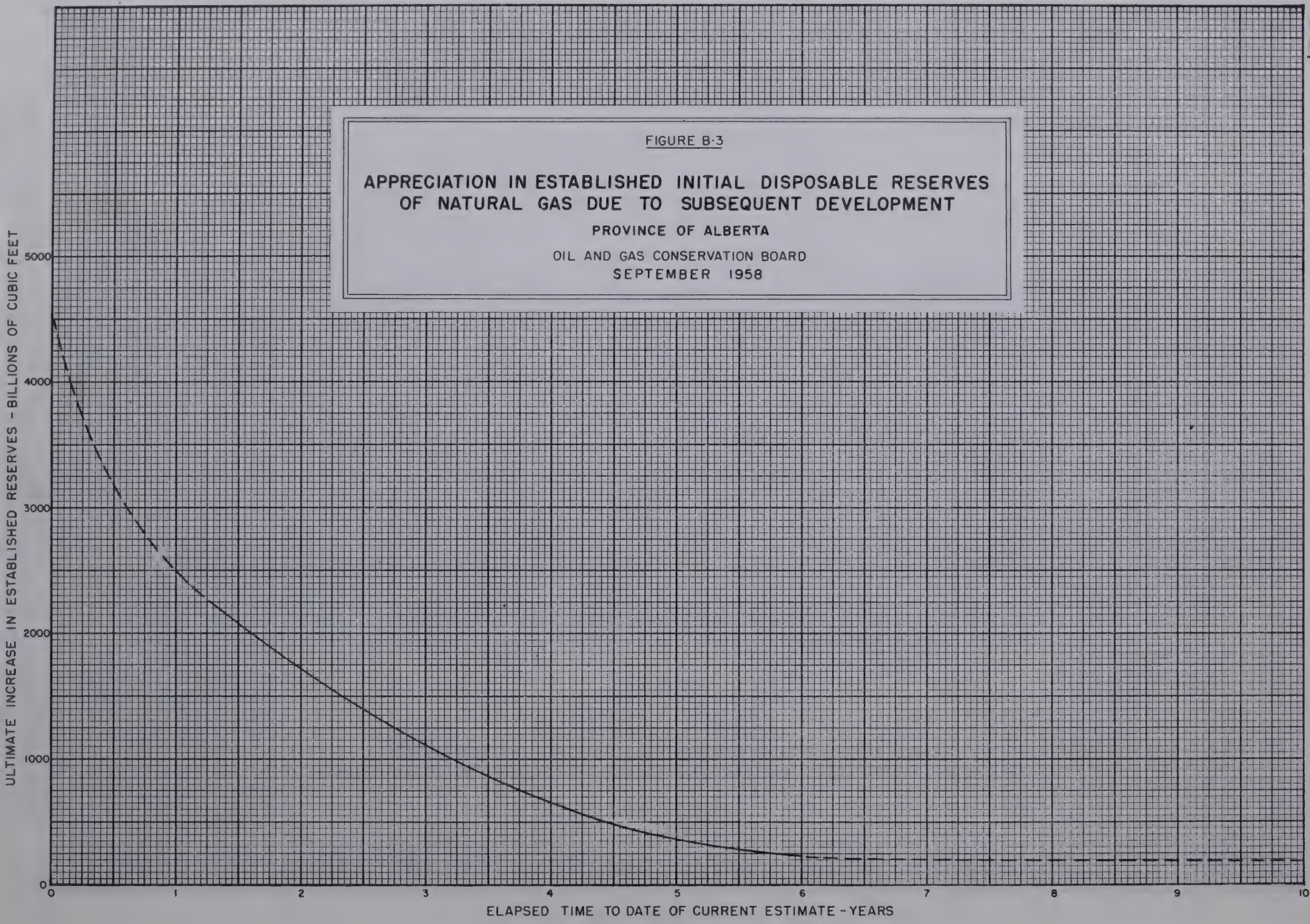


FIGURE B-3

APPRECIATION IN ESTABLISHED INITIAL DISPOSABLE RESERVES OF NATURAL GAS DUE TO SUBSEQUENT DEVELOPMENT

PROVINCE OF ALBERTA

OIL AND GAS CONSERVATION BOARD
SEPTEMBER 1958

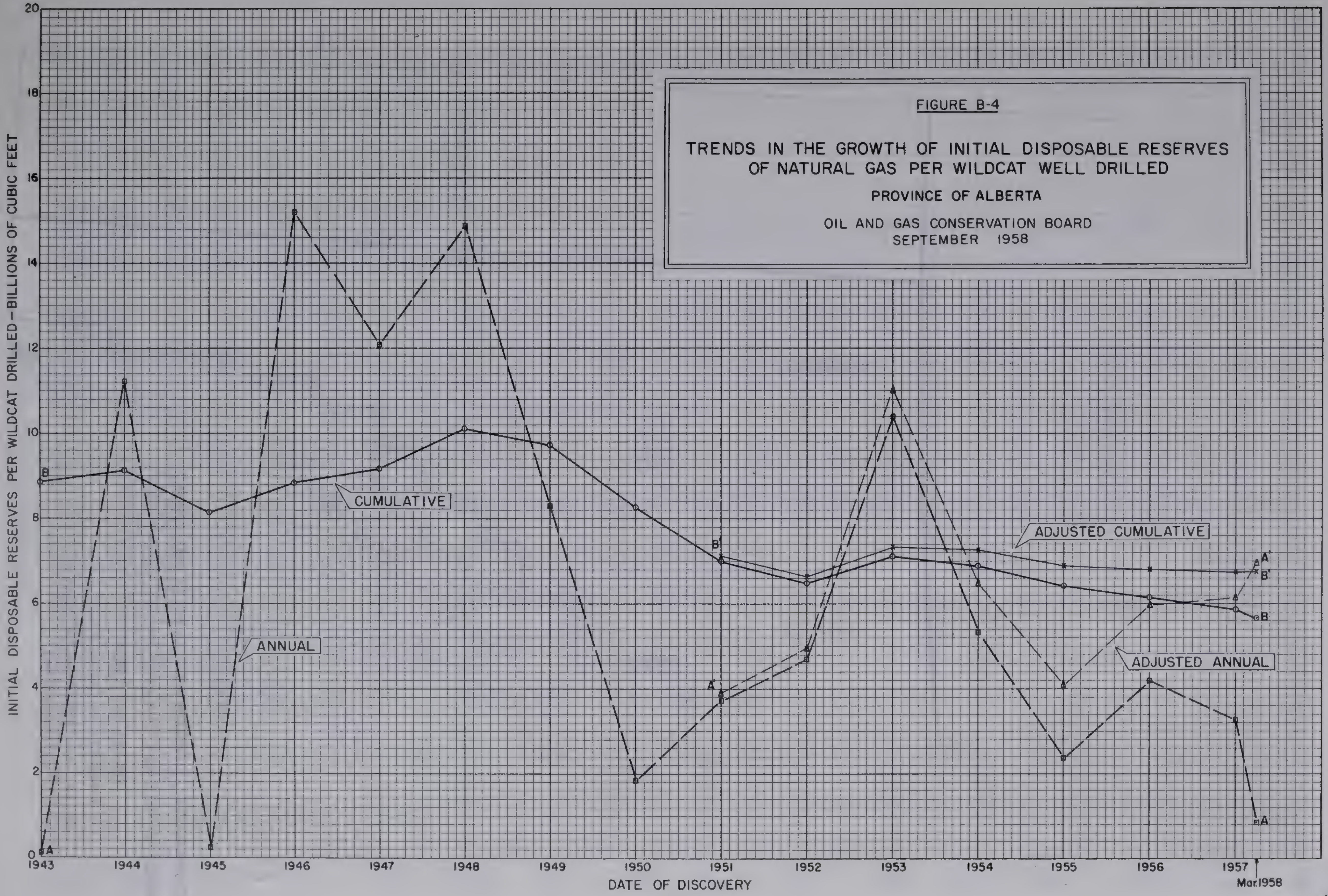


FIGURE B-4

TRENDS IN THE GROWTH OF INITIAL DISPOSABLE RESERVES OF NATURAL GAS PER WILDCAT WELL DRILLED

PROVINCE OF ALBERTA

OIL AND GAS CONSERVATION BOARD
SEPTEMBER 1958

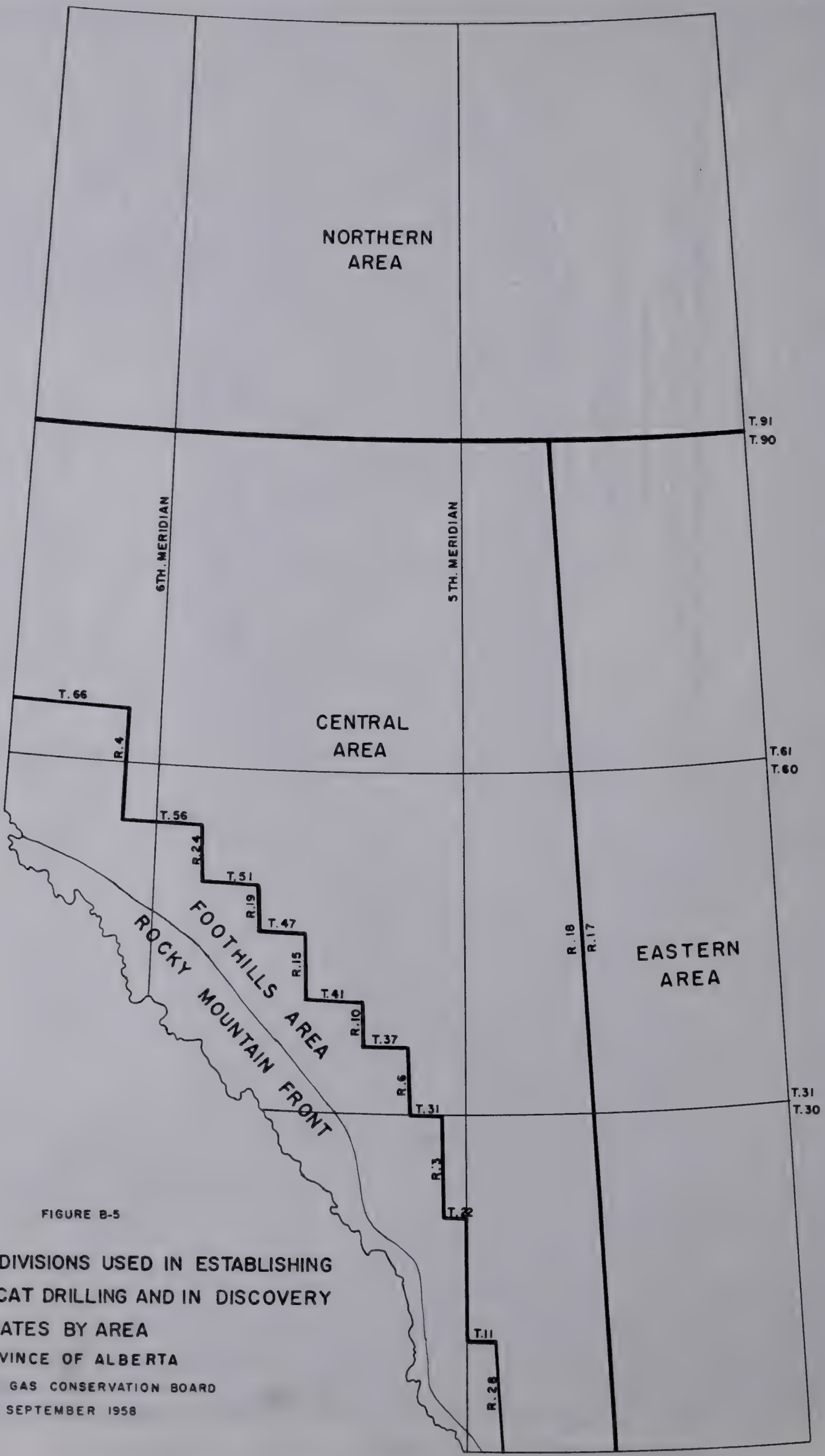


FIGURE B-5

GEOGRAPHICAL DIVISIONS USED IN ESTABLISHING TRENDS IN WILDCAT DRILLING AND IN DISCOVERY RATES BY AREA

PROVINCE OF ALBERTA

OIL AND GAS CONSERVATION BOARD

SEPTEMBER 1958

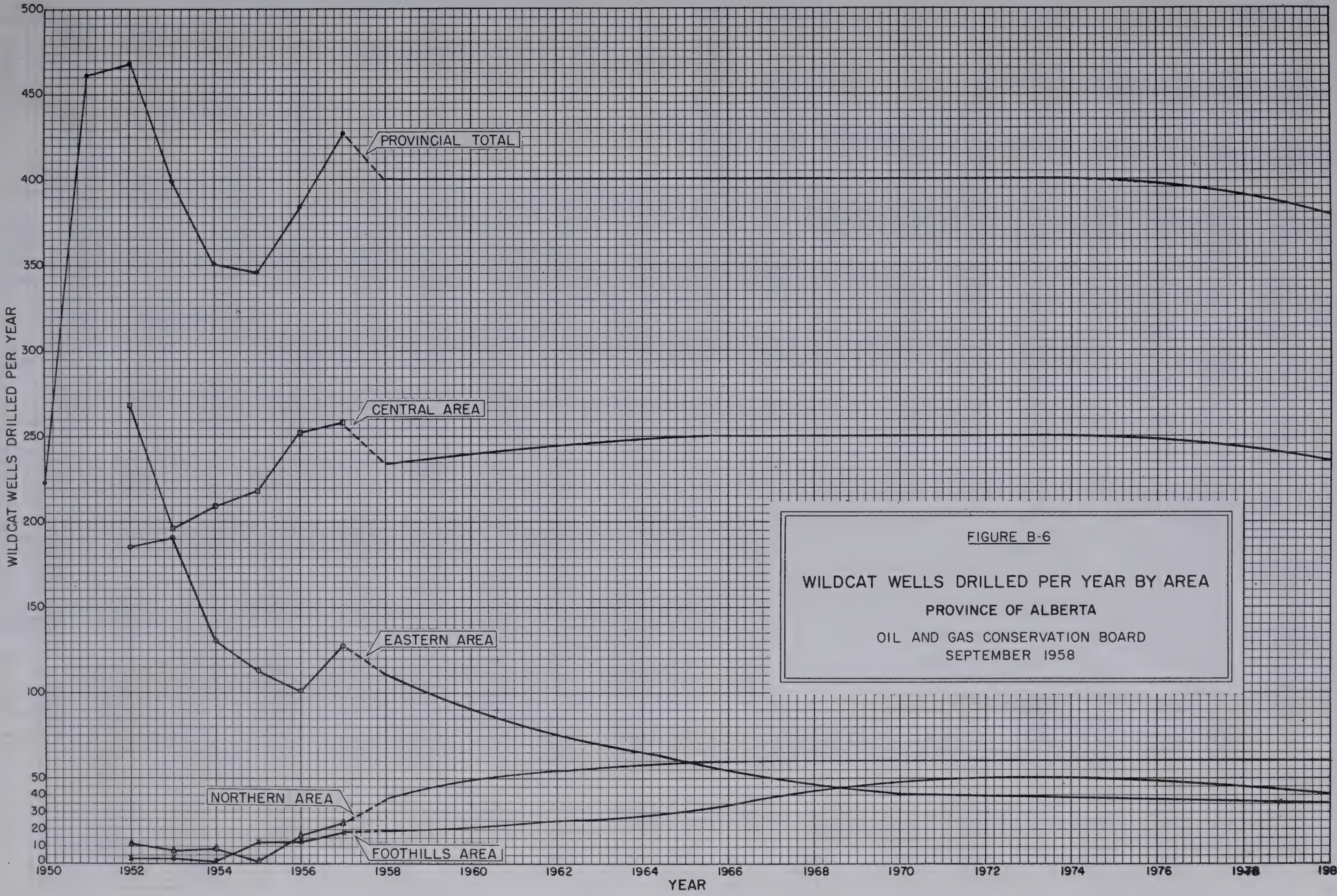


FIGURE B-6

WILDCAT WELLS DRILLED PER YEAR BY AREA

PROVINCE OF ALBERTA

OIL AND GAS CONSERVATION BOARD
SEPTEMBER 1958

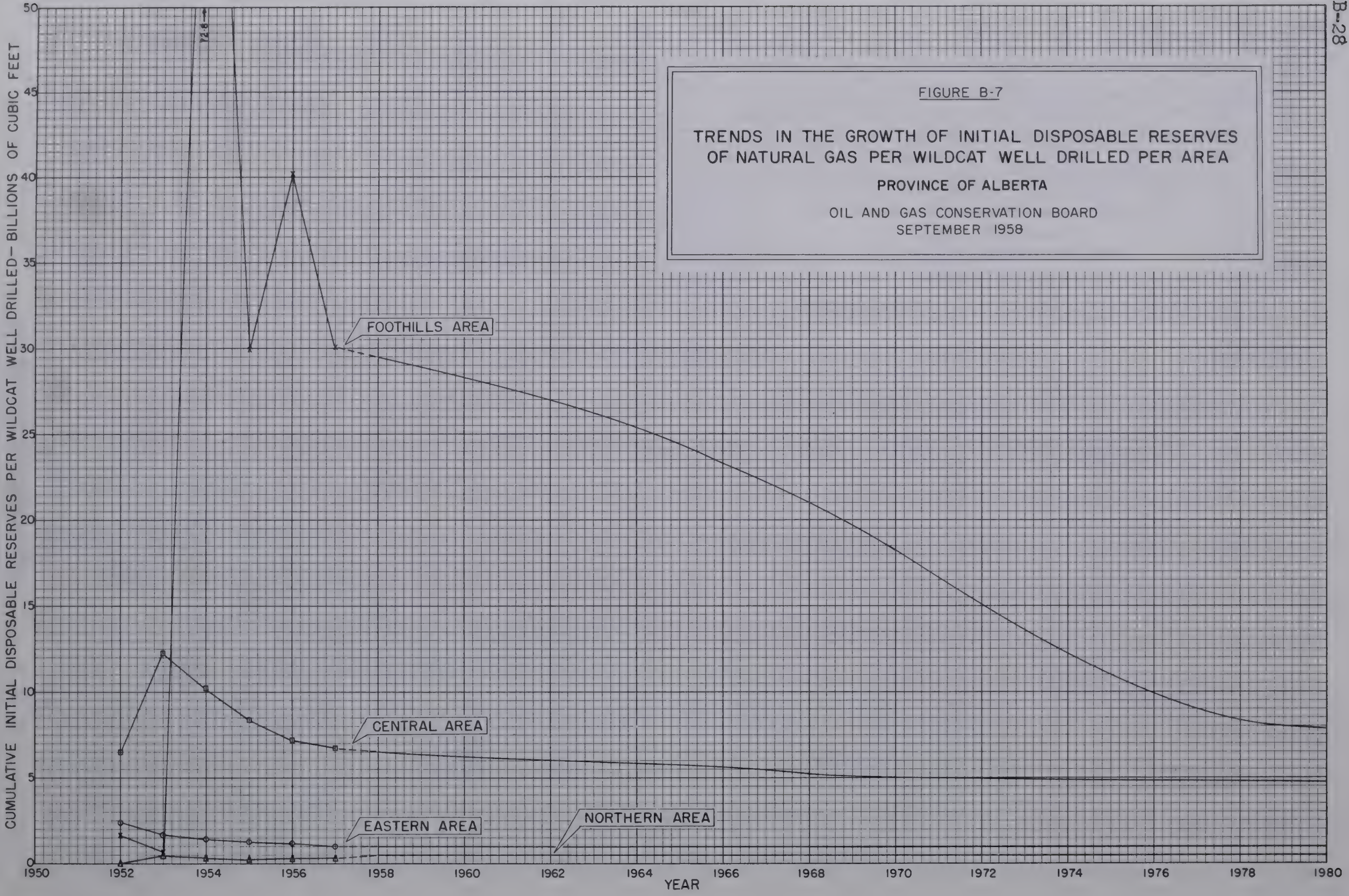


FIGURE B-7

TRENDS IN THE GROWTH OF INITIAL DISPOSABLE RESERVES OF NATURAL GAS PER WILDCAT WELL DRILLED PER AREA

PROVINCE OF ALBERTA

OIL AND GAS CONSERVATION BOARD
SEPTEMBER 1958

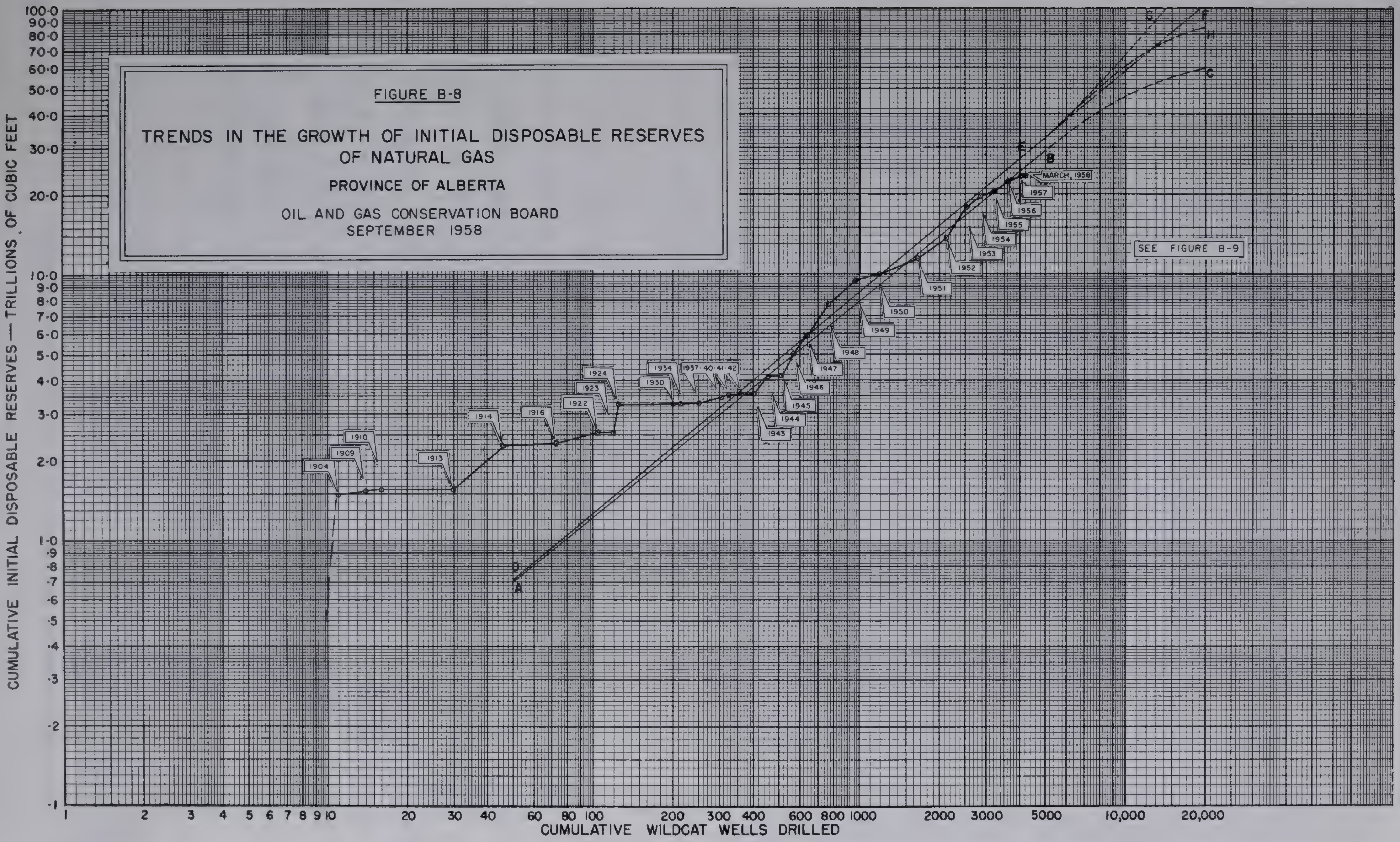


FIGURE B-8

TRENDS IN THE GROWTH OF INITIAL DISPOSABLE RESERVES OF NATURAL GAS

PROVINCE OF ALBERTA

OIL AND GAS CONSERVATION BOARD
SEPTEMBER 1958

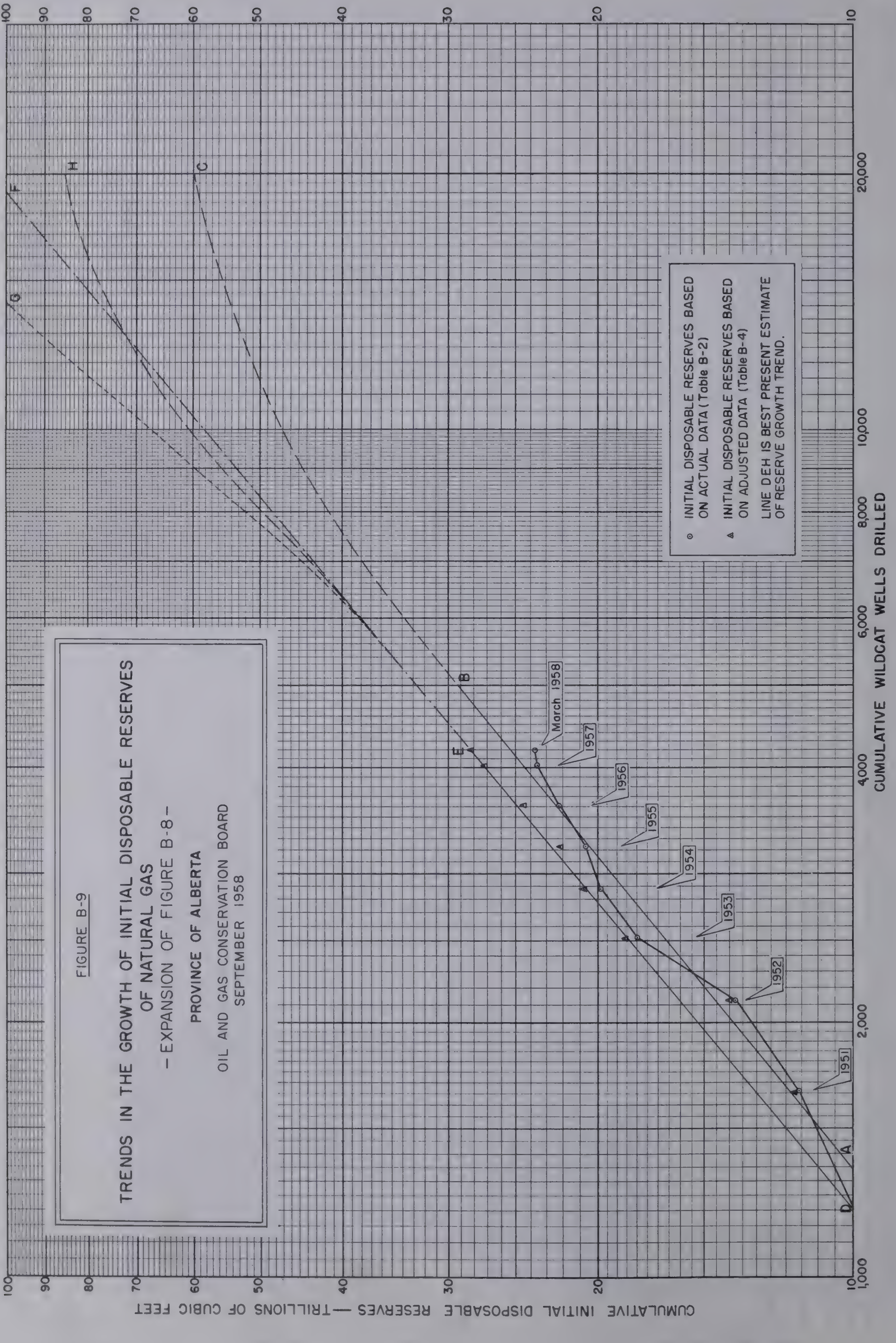


FIGURE B-9

TRENDS IN THE GROWTH OF INITIAL DISPOSABLE RESERVES OF NATURAL GAS

– EXPANSION OF FIGURE B-8 –

PROVINCE OF ALBERTA

OIL AND GAS CONSERVATION BOARD
SEPTEMBER 1958

APPENDIX C

THE PRESENT AND FUTURE GAS REQUIREMENTS OF ALBERTA - PRESENT EXPORT COMMITMENTS - PRESENT AND FUTURE GAS REQUIREMENTS OF CANADIAN MARKETS BEYOND ALBERTA

Alberta Requirements

Briefs regarding estimated future provincial requirements were submitted by Alberta and Southern Gas Co. Ltd., City of Calgary, Canadian Western Natural Gas Company Limited, Northwestern Utilities, Limited and Westcoast Transmission Company Limited.

Estimates of Alberta and Southern

The Stanford Research Institute and Dr. Harries both presented submissions, on behalf of Alberta and Southern, outlining the estimated future provincial requirements of natural gas for domestic, commercial and industrial purposes. These requirements were related to estimates of future population in all cases.

Dr. Harries in evidence stated that he adopted for his purposes the estimates of present and future requirements of natural gas for the Province of Alberta published by the Oil and Gas Conservation Board in its report of January 31, 1957. Concerning industrial requirements of natural gas he said "The figures for industrial demand at this time appear to be a maximum but in the absence of certainty that there will be any shift by new industry from an Alberta location they represent a reasonable estimate."

With regard to future population Dr. Harries indicated that the present high rate of growth could be expected to continue for some time but that immigration would probably be a less important factor in the overall growth. He accepted the Board's population estimate as being realistic in view of the recent growth trends and the assumptions embodied in the estimate.

The Stanford Research Institute gave evidence as to the total Alberta energy requirements (excluding transportation) for the period 1958 to 1970 inclusive, by source and end use. Its estimate of total energy requirements was related directly to population growth. Reference also was made by the Institute to the Board's estimate of Alberta requirements of natural gas in its 1957 report. A comparison of the Institute's estimates and those in the Board's 1957 report follows:

Comparison of Domestic, Commercial and Industrial Requirements as Estimated by Stanford Research Institute and the Board in 1960, 1965 and 1970

(Quantities in Billions of Cubic Feet)

	1960		1965		1970	
Annual Requirements	S.R.I.	Board(1)	S.R.I.	Board(1)	S.R.I.	Board(1)
Domestic	38.4	38.2	50.2	49.5	62.6	56.2
Commercial	28.0	28.0	38.2	35.2	47.6	40.2
Industrial	67.7	101.9	90.1	142.2	111.8	160.6
Total	134.1	168.1	178.5	226.9	222.0	257.0

(1) Board's 1957 Report.

The Institute's domestic and commercial requirements are somewhat higher than those of the Board due to a higher estimate of population growth. On the other hand its estimate of industrial requirements is considerably less than the Board's forecast.

The Institute used a lower industrial growth rate and also postulated that coal and oil would be substituted for gas in certain industries.

Estimates of City of Calgary, Canadian Western Natural Gas Company Limited, Northwestern Utilities, Limited and Westcoast Transmission Company Limited.

The City of Calgary, Canadian Western Natural Gas Company Limited and Westcoast Transmission Company Limited submitted briefs providing details of the estimated requirements of the City of Calgary and the area tributary to the Canadian Western utility system for the next thirty-year period. In all cases the basic method embodied in the briefs consisted of estimating the population for the entire utility system area and applying to these estimates an annual Mcf per capita rate of consumption for each of the classes, Domestic, Commercial and Basic Industrial. The per capita rates were projected from past experience. An allowance for special industrial requirements and new industrial requirements was then added to these estimates. A comparison of these total estimates for a thirty-year period is presented below:

Comparison of Domestic, Commercial and Industrial Requirements of Natural Gas as Estimated for the area tributary to Canadian Western Natural Gas System for the period 1958 - 1987

(Quantities in Billions of Cubic Feet)

		Domestic	Commercial	Industrial	Total
City of Calgary	(1)	754.2	451.9	1,104.3	2,310.4
Canadian Western	(2)	764.2	458.2	1,103.8	2,326.2
Westcoast Transmission	(3)	1,138.6		1,067.3	2,205.9
Board	(4)	706.0	430.7	1,022.7	2,159.4

(1) Exhibit 41.

(2) Exhibit 24 - adjusted to exclude 1957 and to include 1987.

(3) Exhibit 18 - Domestic and Commercial requirements combined.

(4) Board's 1957 Report - adjusted to exclude 1957 and to include 1987.

The estimates submitted are in close agreement but are somewhat higher than the Board's estimate contained in its report dated January 31, 1957, due to a slightly higher population estimate embodied in the estimates presented.

Northwestern Utilities, Limited submitted a brief providing details of the estimated requirements of the City of Edmonton and the area tributary served by its system. Northwestern Utilities, Limited estimated its domestic, commercial and industrial requirements for the period 1957 to 1986 to be 3,197.5 billion cubic feet.

The estimated requirements for the Canadian Western system and the Northwestern Utilities system as estimated by the two utility companies are shown below for selected years and for the thirty-year period 1958 - 1987.

Canadian Western and Northwestern Utilities Systems Requirements (Quantities in Billions of Cubic Feet)

	Canadian Western (1)			Northwestern (1)		
Annual Requirements	Domestic	Commercial	Industrial	Domestic	Commercial	Industrial
1960	15.8	9.5	20.2	18.2	15.1	26.7
1965	19.7	11.8	26.9	22.8	18.4	42.0
1970	23.6	14.1	33.6	27.3	21.7	56.2
1975	27.4	16.4	40.2	31.8	25.0	66.1
1980	31.3	18.8	46.9	36.2	28.2	73.6
1985	35.1	21.0	53.6	40.7	31.5	80.7
Total Requirements for 30 Years						
1958-1987 (2)	764.2	458.2	1,103.7	884.7	699.3	1,725.1

(1) Exhibit 24.

(2) Exhibit 24 - adjusted to exclude 1957 and to include 1987.

Estimates of the Board

In reviewing its 1957 estimates of Alberta's requirements of natural gas, the Board has given consideration both to population growth and to annual per capita rates of consumption. It has taken into consideration the evidence submitted and new information which has been obtained since the last report.

Population

In the light of additional information about population growth made available through local census figures and with consideration given to the various population estimates submitted, the Board believes that its 1957 estimate of population growth over the 30-year period, 1952 to 1981, can be modified to reflect a slightly higher growth rate and a greater concentration of population in urban centres. Based on local census data and other reliable data the mid-1958 population of Alberta was estimated to be 1,202,000 persons. This population figure represents an increase of 7 per cent or 78,884 persons over the 1956 census which recorded the provincial population as 1,123,116 persons.

Consistent with this recent experience it is now estimated that the overall average annual rate of growth will be 3.6 per cent for the period 1952 to 1961 instead of 3.4 per cent as indicated in the 1957 report. A similar increase in growth rates is also anticipated for the periods 1962 to 1971 and 1972 to 1981. It is still assumed that the urban population will be approximately 65 per cent of the total population by 1961 and that all of the urban population will be served with gas by about 1961. It is estimated that with the increasing percentage of urban population and the supply of an increasing number of rural communities with gas, the proportion of the total provincial population served with gas will increase from about 65 per cent in 1961 to near 80 per cent in 1987 (as compared to 75 per cent in 1986 in the 1957 report).

A comparison of the 1957 population estimate with that of the present estimate is given below.

	1957 Estimate		Present Estimate	
	Average Annual Rate of Increase	Terminal Year Population	Average Annual Rate of Increase	Terminal Year Population
1952 - 1961	3.4%	1,310,000	3.6%	1,332,000
1962 - 1971	2.3%	1,643,000	2.4%	1,684,000
1972 - 1981	1.6%	1,932,000	1.7%	1,993,000

The population growth curves for Canada, Alberta, Edmonton and Calgary appear in Figure C-1. The population curve shown for Canada is based on the Gordon Royal Commission Report on the Economic Prospects of Canada.

Domestic and Commercial Requirements

After considering additional experience data and information contained in the various submissions the Board sees no reason for changing the provincial domestic and commercial per capita rates of natural gas consumption. These rates are estimated to increase from the actual figure 28.4 Mcf in 1957, to 31 Mcf in 1960, to 35 Mcf in 1966 for domestic, and from the actual figure of 20.5 Mcf in 1957, to 23 Mcf in 1960, to 25 Mcf in 1966 for commercial.

The Board has made an upward extrapolation in the per capita figures only until 1966 in the belief that per capita consumption may tend to level out by that time. The per capita figures are assumed to be constant from 1967 onward.

The present population projection and unchanged domestic and commercial per capita consumption rates are reflected in small increases in estimated requirements. In addition to being adjusted to normal degree day requirements the revised estimates have been converted to equivalent requirements of natural gas having a heating value of 1,000 Btu per cubic foot. The total domestic and commercial requirements for the period 1958 to 1987 are estimated at 1,800 billion cubic feet and 1,280 billion cubic feet respectively. These figures compare with 1,700 billion cubic feet and 1,210 billion cubic feet previously estimated for the period 1957 to 1986.

Industrial Requirements

Industrial requirements again have been considered under four main categories embracing:

(1) Use of dry or lean natural gas as fuel for industrial processes, steam generation, power plants, etc;

(2) Use of dry or lean natural gas, primarily for its methane content, by the manufacturers of carbon black, ammonia and a relatively few other products which may be produced economically using methane as a raw material;

(3) Use of ethane recovered from residue gas for conversion to ethylene and other products; and

(4) Use of LPG (propane and/or butane) for conversion by partial oxidation or other processes to a wide range of chemicals, use of butane for conversion to butadiene, use of isobutane for the manufacture of alkylate - important constituent of aviation gasoline, etc.

The Board, in its previous reports, stated that it anticipated a rapid increase in the industrial demand for natural gas. Since the 1957 report, the Board has examined additional information concerning the use of natural gas by petrochemical plants, power plants and other industrial plants. In addition, information has been received regarding new expansion programs for existing plants and plans for establishing new industries within the Province. Full consideration has been given to the evidence contained in the various submissions on the future requirements of natural gas for industrial purposes by the utility companies and for the Province as a whole. A re-assessment of all the presently available information leads the Board to believe that considerable expansion in the industrial demand for natural gas can be expected over the next 30 years.

After considering all presently available information on the matter, the Board still believes that the best yardstick for forecasting these industrial requirements is per capita consumption rates related to past trends but adjusted to take into account present conditions together with an allowance for future expansion. The Board has reviewed the industrial per capita rates used in its last report and, in view of recent experience and the present temporary economic recession, has made a revision to the upward extrapolation from the actual 1957 figure of 54.5 Mcf to an estimated 100 Mcf by 1971. It is assumed that the per capita industrial rate will continue to rise at a somewhat slower rate and will reach a saturation of 100 Mcf some five years later than was indicated in the Board's last report.

The present population and the revised industrial per capita consumption rates are reflected in a slight increase in estimated requirements. In addition to being adjusted for normal degree day requirements the revised estimate has been converted to equivalent requirements of natural gas having a heating value of 1,000 Btu per cubic foot. The total industrial requirement for the period 1958 to 1987 is estimated at 4,880 billion cubic feet as compared to 4,800 billion cubic feet previously estimated for the period 1957 to 1986.

Fuel requirements of gas processing plants have not been included in the market estimates since allowance for these requirements has been made in the gas reserve estimates.

Revised Estimates

Investigation of the actual natural gas consumption figure for 1957 reveals that actual consumption was below the estimate by 8.1 billion cubic feet. A comparison of the actual consumption for 1957 with the previous estimate and the revised estimate for 1958 exclusive of field use, processing plant use and storage and exclusive of propane and butane is provided below:

	1957 Actual (1) Bcf	1957 Estimate (2) Bcf	1958 Estimate (2) Bcf
Domestic	33.0	31.8	35.3
Commercial	23.8	22.3	25.5
Industrial	63.3	74.1	72.8
Total	120.1	128.2	133.6

(1) Converted to a normal degree day basis and adjusted to 1,000 Btu per cubic foot heating value.

(2) Adjusted to 1,000 Btu per cubic foot heating value.

The excess of actual consumption in 1957 over estimates for domestic and commercial was due to the fact that the population served with gas for certain areas of the Province increased at a faster rate than was anticipated. The excess of estimated requirements in 1957 over actual consumption for industrial use was due to reduced plant output as a result of the present temporary economic recession.

Figure C-2 contains the unchanged per capita trends in domestic and commercial requirements and the revised per capita trends in industrial requirements. The total annual requirements under each of these categories is obtained by combining the per capita rate with the provincial population projection of Figure C-1. These total requirements are shown in Figure C-3 and in Table C-1. Figure C-4 gives a comparison of the present estimates with the Board's 1957 estimates.

The Board now estimates the total requirements of the Province for the 30-year period, 1958 to 1987, to be about

7,960 billion cubic feet. A comparison with the 1957 report is provided below:

	Report January 31, 1957 (1) (Period 1957-1986) Bcf	Revised (Period 1958-1987) Bcf
Domestic	1,705.7	1,799.6
Commercial	1,210.7	1,279.8
Industrial	4,797.5	4,882.7
Total	7,713.9	7,962.1
Say	7,710.0	7,960.0

(1) Figures given in January 31, 1957, report have been adjusted to 1,000 Btu heating value to provide a proper comparison.

The revised estimates represent an increase of 250 billion cubic feet in the total requirements for the next 30 years. Virtually the entire amount of increase is due to the higher annual requirements that are expected in the one additional terminal year of the forecast period.

These requirements are allocated to the areas tributary to the Canadian Western Natural Gas Company Limited system, the Northwestern Utilities, Limited system, the Medicine Hat - Redcliff area, the Peace River area and the remainder of the Province as shown in Table C-2. This table contains the estimated peak day requirements and the load factors for the five areas. The present allocation of requirements represents the Board's best judgment in the matter and is based on the past proportion of each category in each of the various areas in relation to the total provincial requirements adjusted to take into account any foreseen changes. A comparison with the 1957 report is provided below:

	Report January 31,1957 (1) (Period 1957-1986) Bcf	Revised (Period 1958-1987) Bcf
Area Tributary to CWNG System	2,240	2,305
Area Tributary to NUL System	3,810	3,900
Peace River Area	230	260
Medicine Hat-Redcliff Area	540	550
Remainder of the Province	890	945
Total Provincial Requirements	7,710	7,960

(1) Figures given in January 31, 1957, report have been adjusted to 1,000 Btu per cubic foot heating value to provide a proper comparison.

The estimated requirements of the area tributary to the Canadian Western system have been increased by 65 Bcf over the estimate of the 1957 report. The total for the Northwestern Utilities system has been increased by 90 Bcf. The remaining provincial requirements for the Peace River area, the Medicine Hat - Redcliff area and the remainder of the Province have been increased by 95 Bcf.

Present Export Commitments

Details of the withdrawals of gas authorized under the existing export permits are as follows:

	Maximum Daily MMcf	Maximum Annual Bcf	Total Authorized Withdrawal Bcf	Withdrawn to Dec.31, 1957. Bcf	Remaining Authorized Withdrawal Bcf
Peace River Transmission Company Limited	6	0.6	13	3.5	9.5
Peace River Transmission Company Limited	7	1.0	20	0.9	19.1
Westcoast Transmission Company Limited and Westcoast Transmission Company (Alberta) Ltd.	190	56	1,080	7.8	1,072.2
Canadian-Montana Pipeline Company	100	20	257*	-*	257.0*
Saskatchewan Power Corporation	83	18	223	-	-
Trans-Canada Pipe Lines Limited	620	183	4,350	2.8	4,347.2
Total	1,006	278.6	5,943	72.9	5,705.0

* All the gas from Black Butte, Comrey, Manyberries, Pendant D'Oreille and Smith Coulee fields. Reserves in these fields are presently estimated at 257 billion cubic feet. Withdrawn to December 31, 1957, equals 57.9 billion cubic feet.

Future Requirements of Canadian Markets Beyond Alberta

The Board has given consideration to other Canadian requirements in determining the amount of surplus gas which might be exported out of Canada. This has been done in accordance with the policy, adopted by the Alberta Government and set forth in a brief presented to the Borden Commission by Premier E. C. Manning, of giving first priority to Alberta requirements and second priority to other Canadian requirements (within range of economic feasibility).

Alberta gas, through the facilities of Trans-Canada Pipe Lines Limited, is now supplying markets in Saskatchewan, Manitoba, Ontario and Quebec. British Columbia is also being served with Alberta gas through the facilities of the Westcoast Transmission Company Limited and the Peace River Transmission Company Limited. Gas from the Medicine Hat Field will start flowing in September to markets in Saskatchewan through facilities owned by the Saskatchewan Power Corporation.

Trans-Canada Pipe Lines Limited presented a brief prepared by Commonwealth Services Inc. showing its estimated requirements for the next 30 years to be some 18.8 trillion cubic feet. In response to a request from the Board for details as to what fuels gas sales would displace in its marketing areas, Trans-Canada filed information with respect to the year 1962-1963 for the Ontario and Quebec markets. In the Company's opinion sales of interruptible gas would displace some 18 million barrels of oil (49,000 barrels per day) in 1962-1963. Of this amount some 8 million barrels would be heavy fuel oil. It was pointed out that some 2 million, 9 hundred thousand barrels of this fuel was imported from foreign sources during 1957.

Alberta and Southern, while recognizing that Canadian requirements would have to be given priority, criticized Commonwealth Services' estimate of Trans-Canada requirements on the grounds it was unrealistic. Alberta and Southern maintained, on the basis of a cost of service estimate prepared and presented by Mr. Hough of Pacific Gas and Electric Company, that the cost of gas delivered to Eastern Canada would be too high to permit the development of the large firm loads forecasted and, consequently, interruptible sales would not materialize as predicted. Alberta and Southern pointed out that if industrial sales were made at prices lower than cost of service it would be detrimental to residential and commercial customers.

Alberta and Southern further claimed that Trans-Canada had failed to give evidence adequately supporting its load forecasts which were far in excess of United States experience under comparable conditions and which were unrealistic because they failed to take into proper account the price relationship that will exist between natural gas and competitive fuels.

Mr. Coates, President of Trans-Canada, in giving evidence stated:

"As to Trans-Canada's policy in connection with the purchase of gas and its movement from the Province of Alberta east through the facilities of Trans-Canada, it is Trans-Canada's feeling that the Petroleum and Natural Gas Conservation Board here not take cognizance of the fact or any recognition of the fact that there may be required by Trans-Canada over the next 30 years some 18 to 20 trillion cubic feet of gas. We believe that in order to finance any new facilities it is necessary that we have gas firmly under contract and permits to remove it from the Province. We expect to purchase additional gas from time to time and to make applications to this Board for its removal from the Province if it is excess to the needs of the Province.

"As far as the market study is concerned, we feel that the company must depend on the trend of developments for additional gas as the market develops down through the years.

"As far as the 30-year projection is concerned, I think it is very, very difficult for any of us to look that far ahead and with real certainty know the events projected for 30 years will come to pass just as they are projected. In this particular type of business that we are in, a reasonable forecast, or, rather, certain forecasts can be made for a 5-year period. Beyond that, as far as gas supplies are concerned, we will just have to rely on the fact that

> there will be additional gas found, and from geological information that has been available to all of us from time to time, indications are that a great deal more gas will be found in Alberta during that period."

The Board believes that proper effect could be given to the principle of priority to other Canadian requirements by

(1) providing that only gas surplus to Alberta requirements and to the immediately contractable requirements of other Canadian provinces should be exported outside Canada, and

(2) further providing that there be satisfactory evidence, on the basis of trends in the growth of reserves, that adequate future reserves will be available to meet the estimated long term twenty-five year requirements of other Canadian provinces.

Requirements estimated as far as 25 years into the future are not accurately defined and must be subject to continual review and revision. Producers, transmission companies and distributing companies are financially unable to contract to meet fully such long term estimated future needs. The estimated 25 year future requirements of Canadian markets for natural gas may therefore, realistically, be considered in two portions: the immediately contractable future requirement and the remaining, less definite, long term future requirement.

The Board has given no consideration at this time to the requirements of British Columbia, because its own reserves, together with the Alberta reserves committed to it under export permits, should be adequate.

The Board considers that the other future Canadian requirements within the range of economic feasibility are represented by Trans-Canada's future Canadian requirements.

The Board has prepared its own estimate of future fuel energy requirements for Ontario and Quebec, together with an estimate of future gas requirements. These are presented in Table C-3, together with estimates prepared by the Economic Research Corporation Limited (ERC), Montreal, and Stanford Research Institute (SRI), the Gordon Commission (Canadian Energy Prospects by John Davis, p. 311) and Trans-Canada (Commonwealth Services Inc.). The ERC and SRI estimates were prepared for Alberta and Southern and presented to the Borden Royal Commission. They have been included for comparative purposes only, the Board being fully aware that Trans-Canada expressed to the Borden Commission its complete disagreement with the projected gas requirements.

The Gordon Commission forecast has been adjusted to include gasoline with other fuels on a regional basis and the regional requirements have been expressed in terms of natural gas equivalents.

The average annual rate of growth of the future requirements of energy fuels in Ontario and Quebec has been conservatively estimated at 2.8 per cent by the Gordon Commission and at 3.1 per cent by ERC and SRI. The Board has embodied an average annual growth rate of some 3.5 per cent in its estimate of future requirements to provide for a somewhat higher demand for energy fuels. When fitted to the respective total energy fuel curves, the various estimates of natural gas consumption predict varying degrees of displacement of coal and oil within the overall energy requirements.

The ERC and SRI estimate assumes that natural gas will capture some 7 per cent of the total energy fuel market by 1960 and this share will increase to some 16 per cent by 1980. The Trans-Canada estimate of natural gas sales when related to the Board's estimate of total energy fuel markets assumes that natural gas will capture some 10 per cent of the market in 1960 and this share will increase to some 26 per cent by 1980. The Board's estimate assumes that natural gas sales will displace competitive fuels over the first ten years in line with that projected by Trans-Canada but will tend to level out around 1968 and increase thereafter at a rate parallel to that estimated for total energy fuels.

The Board believes that natural gas will compete effectively with other fuels for some 19 per cent of the total energy fuels market by 1968, but that it will not gain significantly thereafter. This assumption appears realistic in view of the likelihood of possible increases in the price of natural gas at the well head and active competition from the firmly established coal and oil fuels in the Ontario and Quebec markets, particularly in the case of industrial fuels.

Table C-4 presents the Board's estimate of Trans-Canada's requirements for the next 25 years for the Canadian markets that it is now serving.

The annual sales indicated for the first five years are essentially those provided to the Board by Trans-Canada and are believed to be accurate. The annual sales shown for the following 20 years are considered to be a reasonable estimate of the future annual natural gas requirements of Trans-Canada. The total requirements for the next 25-year period are estimated to be 10.3 trillion cubic feet. Trans-Canada estimates a 25-year requirement of some 12.3 trillion cubic feet. This is after giving effect to some changes in the first 5-year requirements suggested by the Company. The estimate given to the Borden Royal Commission by ERC and SRI indicates that the total requirements of Trans-Canada for the next 25-year period amount to some 7.1 trillion cubic feet.

The Board, after consultation with officials of the Company, have set Trans-Canada's contractable Canadian requirements at 1.5 trillion cubic feet which have been provided for out of established reserves as discussed in Appendix D and E. The balance of the twenty-five year requirements has been provided for out of future reserves.

Interruptible Gas and Storage Facilities

The sales of Alberta gas in Eastern Canada will displace a significant amount of Alberta oil and this is particularly true with respect to interruptible sales of gas which must be sold below the cost of other fuels, such as Bunker C oil, to make it attractive to the customer to maintain stand-by equipment to use an alternative fuel when gas is cut off. Interruptible sales represent 27.4 per cent of Trans-Canada's own thirty-year estimate of requirements.

The Board believes that there should be a proper combination of the use of interruptible sales and market-end storage. The Board agrees that a certain amount of interruptible sales is in the interests of both the consumer and the producer, but it also believes that indiscriminate use of interruptible sales to build a very high load factor may not be in the interests of either the consumer or the producer. While Alberta has not had experience with interruptible sales, the misuses of such sales in the United States were brought to light in a report of the Federal Power Commission in 1948. It was found in some cases, due to over-design of line, that interruptible sales were in fact firm sales and also that interruptible sales were not bearing a fair share of transportation costs, all of which reacted to the detriment of firm consumers.

At the request of the Board, Trans-Canada filed information with respect to the use of gas storage facilities in the province of Ontario. Trans-Canada stated it does not own storage facilities but benefits greatly from the storage fields controlled by Union Gas Company. All of Union's peak demand and part of Consumer's Gas Company's peak demand are met from these fields. If Union's storage facilities were not available, Trans-Canada claims its overall operating load factor would be reduced from 90 per cent to 65 per cent. The Board is of the opinion that Ontario storage facilities should be utilized to the fullest extent possible to meet the peak demands of the eastern market and that Trans-Canada should always be on the look-out to acquire storage facilities of its own.

TABLE C - 1

OIL AND GAS CONSERVATION BOARD

ESTIMATE OF NATURAL GAS REQUIREMENTS

PROVINCE OF ALBERTA, JANUARY 1, 1958 - DECEMBER 31, 1987

(QUANTITIES ARE BASED ON NORMAL DEGREE DAYS AND ADJUSTED TO 1,000 BTU VALUE PER CUBIC FOOT)

1 YEAR	2 DOMESTIC BILLIONS OF CUBIC FEET	3 COMMERCIAL BILLIONS OF CUBIC FEET	4 INDUSTRIAL BILLIONS OF CUBIC FEET	5 TOTAL BILLIONS OF CUBIC FEET
1958	35.3	25.5	72.8	133.6
1959	37.9	27.7	81.7	147.3
1960	40.5	29.3	91.1	160.9
1961	43.3	31.0	101.1	175.4
1962	45.9	32.3	106.9	185.1
1963	47.5	33.9	113.1	194.5
1964	49.3	35.4	119.3	204.0
1965	51.2	37.0	125.9	214.1
1966	53.2	37.8	132.8	223.8
1967	54.5	38.8	139.8	233.1
1968	55.8	39.6	147.0	242.4
1969	57.1	40.6	154.8	252.5
1970	58.8	41.4	162.6	262.8
1971	59.9	42.4	170.8	273.1
1972	60.9	43.2	173.8	277.9
1973	62.0	44.0	176.7	282.7
1974	63.0	44.7	179.8	287.5
1975	64.1	45.5	182.8	292.4
1976	65.1	46.2	185.7	297.0
1977	66.3	47.0	189.0	302.3
1978	67.4	47.9	192.2	307.5
1979	68.5	48.7	195.3	312.5
1980	69.8	49.5	198.8	318.1
1981	71.0	50.3	202.1	323.4
1982	72.0	51.1	205.5	328.6
1983	73.3	52.0	209.1	334.4
1984	74.6	52.9	212.6	340.1
1985	75.8	53.8	216.3	345.9
1986	77.2	54.7	219.8	351.7
1987	78.4	55.6	223.5	357.5
TOTALS	1799.6	1279.8	4882.7	7962.1
SAY	1800.0	1280.0	4880.0	7960.0

TABLE C - 2

OIL AND GAS CONSERVATION BOARD

ESTIMATE OF NATURAL GAS REQUIREMENTS

PROVINCE OF ALBERTA, JANUARY 1, 1958 - DECEMBER 31, 1987

ALLOCATION BETWEEN AREAS TRIBUTARY TO THE DISTRIBUTING SYSTEM

(QUANTITIES ARE BASED ON NORMAL DEGREE DAYS AND ADJUSTED TO 1,000 BTU VALUE PER CUBIC FOOT)

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
	AREA TRIBUTARY TO C.W.N.G. SYSTEM			AREA TRIBUTARY TO N.U.L. SYSTEM			PEACE RIVER AREA			MEDICINE HAT - REDCLIFF AREA			REMAINDER OF THE PROVINCE			TOTAL PROVINCIAL REQUIREMENTS		
YEAR	ANNUAL BILLIONS OF CUBIC FEET	PEAK DAY MMCF	LOAD FACTOR PER CENT	ANNUAL BILLIONS OF CUBIC FEET	PEAK DAY MMCF	LOAD FACTOR PER CENT	ANNUAL BILLIONS OF CUBIC FEET	PEAK DAY MMCF	LOAD FACTOR PER CENT	ANNUAL BILLIONS OF CUBIC FEET	PEAK DAY MMCF	LOAD FACTOR PER CENT	ANNUAL BILLIONS OF CUBIC FEET	PEAK DAY MMCF	LOAD FACTOR PER CENT	ANNUAL BILLIONS OF CUBIC FEET	PEAK DAY MMCF	LOAD FACTOR PER CENT
1958	40.0	267	41	63.5	370	47	2.6	18	40	12.5	50	69	15.0	103	40	133.6	808	45
1959	43.5	291	41	70.0	400	48	3.2	22	40	13.0	51	70	17.6	121	40	147.3	885	46
1960	47.1	314	41	76.7	428	49	3.8	26	40	13.3	52	70	20.0	137	40	160.9	957	46
1961	51.3	335	42	84.2	461	50	4.2	28	41	13.8	54	70	21.9	150	40	175.4	1028	47
1962	54.4	355	42	89.2	479	51	4.4	29	41	14.2	56	70	22.9	157	40	185.1	1076	47
1963	57.2	373	42	94.3	507	51	4.7	31	41	14.6	57	70	23.7	162	40	194.5	1130	47
1964	60.0	390	42	99.7	534	51	5.1	34	41	14.9	58	70	24.3	166	40	204.0	1182	47
1965	63.1	412	42	105.1	565	51	5.7	38	41	15.4	60	70	24.8	170	40	214.1	1245	47
1966	65.6	418	43	109.9	590	51	6.3	41	42	15.8	62	70	26.2	179	40	223.8	1290	47
1967	68.3	435	43	114.5	615	51	6.8	44	42	16.1	63	70	27.4	188	40	233.1	1345	47
1968	70.7	449	43	119.0	638	51	7.2	47	42	16.5	64	70	29.0	198	40	242.4	1396	47
1969	73.1	466	43	124.2	667	51	7.4	48	42	16.9	66	70	30.9	212	40	252.5	1459	47
1970	76.0	484	43	129.2	694	51	7.7	50	42	17.2	67	70	32.7	224	40	262.8	1519	47
1971	78.5	489	44	134.4	722	51	8.2	52	43	17.6	69	70	34.4	236	40	273.1	1568	48
1972	79.8	496	44	136.8	719	52	8.5	54	43	18.1	71	70	34.7	237	40	277.9	1577	48
1973	81.5	507	44	138.8	731	52	9.0	57	43	18.4	72	70	35.0	240	40	282.7	1607	48
1974	82.8	516	44	141.0	743	52	9.4	60	43	19.0	74	70	35.3	242	40	287.5	1635	48
1975	84.1	524	44	143.5	756	52	9.8	62	43	19.5	76	70	35.5	243	40	292.4	1661	48
1976	85.5	519	45	145.9	767	52	10.1	63	44	19.7	77	70	35.8	245	40	297.0	1671	49
1977	87.0	530	45	148.6	783	52	10.4	65	44	20.3	79	70	36.0	247	40	302.3	1704	49
1978	88.6	539	45	151.2	797	52	10.8	67	44	20.6	81	70	36.3	249	40	307.5	1733	49
1979	90.0	548	45	153.7	810	52	11.1	69	44	21.0	82	70	36.7	251	40	312.5	1760	49
1980	91.6	556	45	156.3	821	52	11.5	71	44	21.6	84	70	37.1	253	40	318.1	1785	49
1981	93.2	567	45	159.0	838	52	11.8	72	45	21.9	86	70	37.5	257	40	323.4	1820	49
1982	94.6	576	45	161.5	851	52	12.3	75	45	22.4	88	70	37.8	259	40	328.6	1849	49
1983	96.5	588	45	164.3	866	52	12.6	77	45	22.8	89	70	38.2	262	40	334.4	1882	49
1984	98.0	595	45	167.2	879	52	12.8	78	45	23.3	91	70	38.8	265	40	340.1	1908	49
1985	99.7	607	45	170.0	896	52	13.2	80	45	23.9	94	70	39.1	268	40	345.9	1945	49
1986	101.3	617	45	172.9	911	52	13.5	82	45	24.3	95	70	39.8	273	40	351.7	1978	49
1987	103.0	627	45	175.8	926	52	13.4	82	45	25.0	98	70	40.2	275	40	357.5	2008	49
TOTALS	2306.0			3900.4			257.5			553.6			944.6			7962.1		
SAY	2305.0			3900.0			260.0			550.0			945.0			7960.0		

TABLE C - 3

COMPARISON OF GROWTH IN ENERGY FUEL REQUIREMENTS FOR ONTARIO AND QUEBEC

IN BILLIONS OF CUBIC FEET OF NATURAL GAS EQUIVALENT
(EXCLUDING FUELS USED FOR THE GENERATION OF ELECTRICITY)

1	2	3	4	5	6	7	8	9	10	11	12	13
	ERC AND SRI				GORDON COMMISSION(A)		BOARD'S ESTIMATE				TRANS-CANADA(B)	
YEAR	TOTAL FUELS BCF	AVERAGE ANNUAL INCREASE PER CENT	GAS SALES BCF	GAS AS PERCENTAGE OF TOTAL FUELS	TOTAL FUELS BCF	AVERAGE ANNUAL INCREASE PER CENT	TOTAL FUELS BCF	AVERAGE ANNUAL INCREASE PER CENT	GAS SALES BCF	GAS AS PERCENTAGE OF TOTAL FUELS	GAS SALES BCF	GAS AS PERCENTAGE OF TOTAL FUELS
1948	1170	-	8	0.8	-	-	-	-	-	-	-	-
1950	1184	0.6	9	0.8	-	-	-	-	-	-	-	-
1952	1234	2.1	11	0.9	-	-	-	-	-	-	-	-
1954	1259	1.0	14	1.1	1227	-	-	-	-	-	-	-
1956	1472	8.1	26	1.8	1297	2.8	-	-	-	-	-	-
1957	1485	0.9	36	2.4	1333	2.8	-	-	-	-	-	-
1958	1420	-4.4	58	4.1	1370	2.8	1470	-	50	3.4	50	3.4
1959	1490	4.9	92	6.2	1409	2.8	1522	3.5	112	7.4	112	7.4
1960	1532	2.8	104	6.8	1448	2.8	1575	3.5	159	10.1	159	10.1
1961	1566	2.2	123	7.9	1489	2.8	1629	3.5	203	12.5	203	12.5
1962	1599	2.1	139	8.7	1531	2.8	1687	3.5	255	15.1	255	15.1
1963	1653	3.4	157	9.5	1574	2.8	1746	3.5	276	15.8	254	14.5
1964	1704	3.1	170	10.0	1618	2.8	1807	3.5	296	16.4	280	15.5
1965	1757	3.1	184	10.5	1663	2.8	1870	3.5	323	17.3	299	16.0
1966	1811	3.1	199	11.0			1935	3.5	348	18.0	331	17.1
1967	1867	3.1	215	11.5			2003	3.5	370	18.5	359	17.9
1968	1928	3.1	232	12.0			2073	3.5	394	19.0	394	19.0
1969	1988	3.1	245	12.3			2146	3.5	400	18.5	428	19.9
1970	2050	3.1	259	12.6			2221	3.5	410	18.5	456	20.5
1975	2390	3.1	338	14.1			2638	3.5	492	19.0	625	23.7
1980	2779	3.1	433	15.6			3133	3.5	584	19.0	816	26.0

(A) Canadian Energy Prospects by John Davis, Page 311 - data adjusted to include gasolines with other fuels on a regional basis and the total regional fuels given in tons of coal have been converted to natural gas equivalents on the basis of one ton of coal equal to 26,000 cubic feet of gas.

(B) Gas Sales includes those for Trans-Canada Pipe Lines Limited and Union Gas Company.

TABLE C - 4

FORECAST OF ENERGY FUEL REQUIREMENTS OF QUEBEC AND ONTARIO
AND
BOARD'S ESTIMATE OF TRANS-CANADA'S REQUIREMENTS TO SERVE QUEBEC, ONTARIO, MANITOBA AND SASKATCHEWAN

1	2	3	4	5	6	7	8	9	10
							TRANS-CANADA REQUIREMENTS		
YEAR	ENERGY FUELS[A] (QUE - ONT) BCF	GAS SALES (QUE - ONT) BCF	GAS AS PERCENTAGE OF TOTAL FUELS (QUE - ONT)	LESS PRODUCTION AND IMPORTS[B] (QUE - ONT) BCF	PLUS GAS SALES (C) MANITOBA BCF	PLUS GAS SALES (C) SASKATCHEWAN BCF	ANNUAL SALES BCF	PEAK DAY SALES BCF	LOAD FACTOR PER CENT
1958	1470	50	3.4	33	6	4	27	280	26
1959	1522	112	7.4	24	10	3	101	452	61
1960	1575	159	10.1	19	11	4	155	587	72
1961	1629	203	12.5	19	12	4	200	723	77
1962	1687	255	15.1	19	14	4	254	847	83
1963	1746	276	15.8	17	15	4	278	847	90
1964	1807	296	16.4	12	15	4	303	922	90
1965	1870	323	17.3	12	15	4	330	1004	90
1966	1935	348	18.0	10	16	4	358	1090	90
1967	2003	370	18.5	10	18	4	382	1162	90
1968	2073	394	18.5	9	20	4	409	1245	90
1969	2146	400	18.5	9	22	4	417	1268	90
1970	2221	410	18.5	4	24	4	433	1320	90
1971	2299	428	19.0	4	26	4	454	1382	90
1972	2379	443	19.0	4	27	4	470	1430	90
1973	2463	459	19.0	4	29	4	488	1487	90
1974	2549	475	19.0	4	31	4	506	1540	90
1975	2638	492	19.0	4	33	4	525	1598	90
1976	2731	509	19.0	4	35	4	544	1657	90
1977	2826	527	19.0	4	37	4	564	1720	90
1978	2925	545	19.0	4	40	4	585	1780	90
1979	3027	565	19.0	4	41	4	606	1845	90
1980	3133	584	19.0	4	43	4	627	1908	90
1981	3243	604	19.0	4	45	4	649	1976	90
1982	3356	626	19.0	4	47	4	673	2050	90
TOTAL		9839		232	632	99	10338		

(A) ENERGY FUELS IN BILLIONS OF CUBIC FEET OF NATURAL GAS EQUIVALENT-EXCLUDING FUELS USED FOR THE GENERATION OF ELECTRICITY.

(B) INCLUDES PRODUCTION OF NATURAL GAS IN ONTARIO AND IMPORTS OF NATURAL GAS FROM THE UNITED STATES AS INDICATED IN THE "SUBMISSION TO THE ROYAL COMMISSION ON ENERGY" BY UNION GAS COMPANY.

(C) SALES OF NATURAL GAS IN MANITOBA AND SASKATCHEWAN BASED ON EXHIBIT 47 OF THE WESTCOAST TRANSMISSION COMPANY LIMITED HEARINGS.

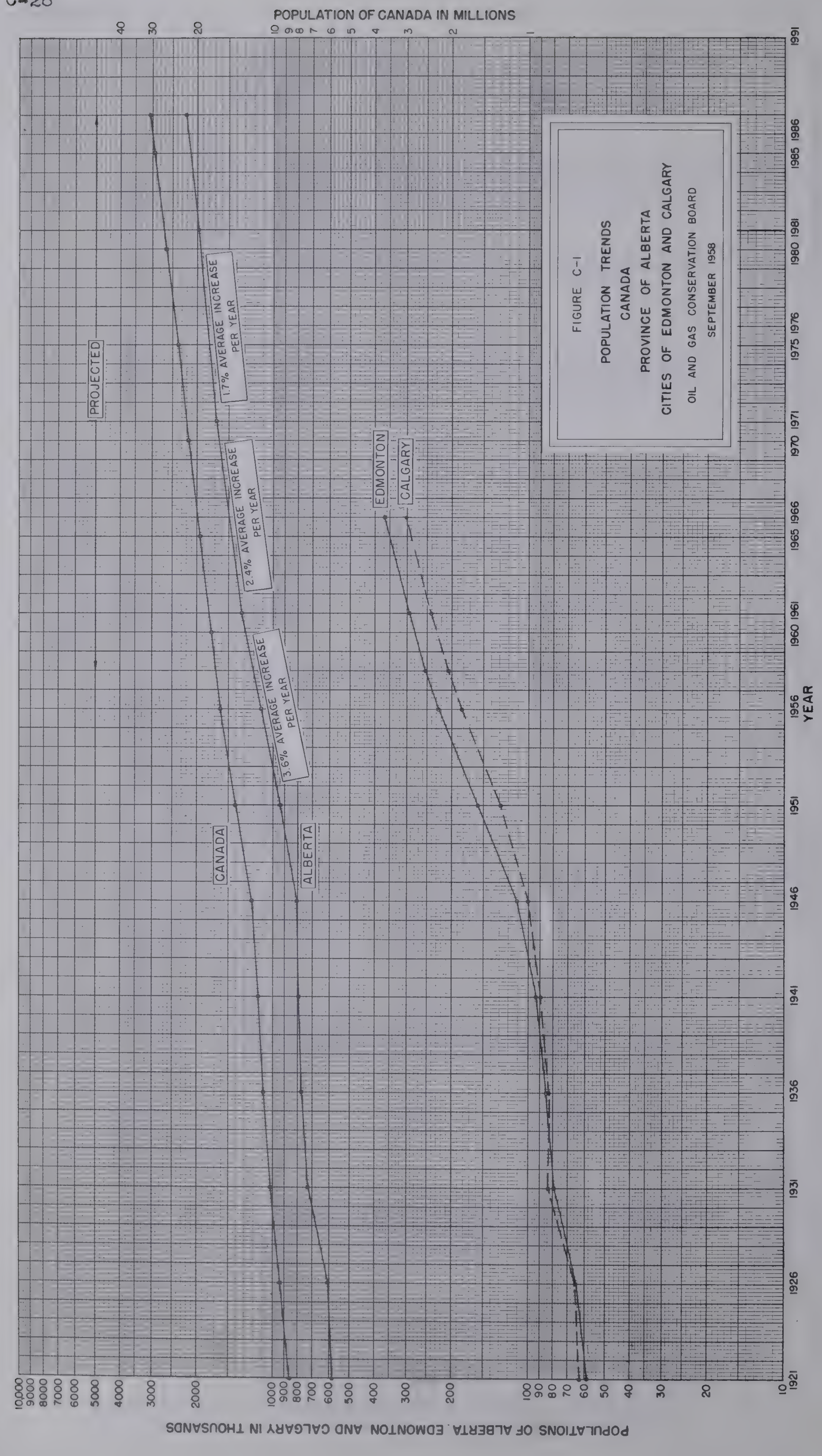


FIGURE C-1
POPULATION TRENDS
CANADA
PROVINCE OF ALBERTA
CITIES OF EDMONTON AND CALGARY
OIL AND GAS CONSERVATION BOARD
SEPTEMBER 1958

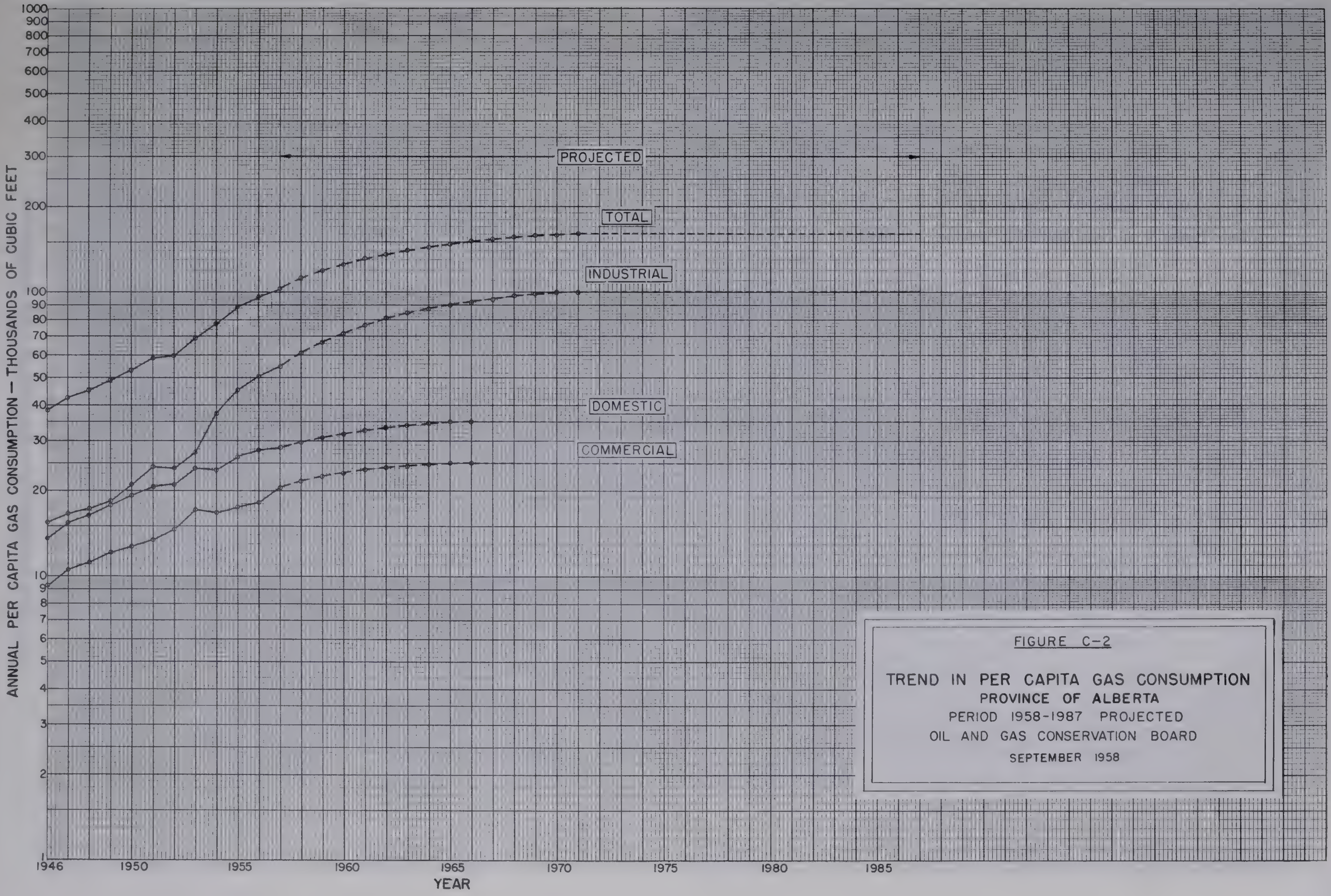


FIGURE C-2

TREND IN PER CAPITA GAS CONSUMPTION
PROVINCE OF ALBERTA
PERIOD 1958-1987 PROJECTED
OIL AND GAS CONSERVATION BOARD
SEPTEMBER 1958

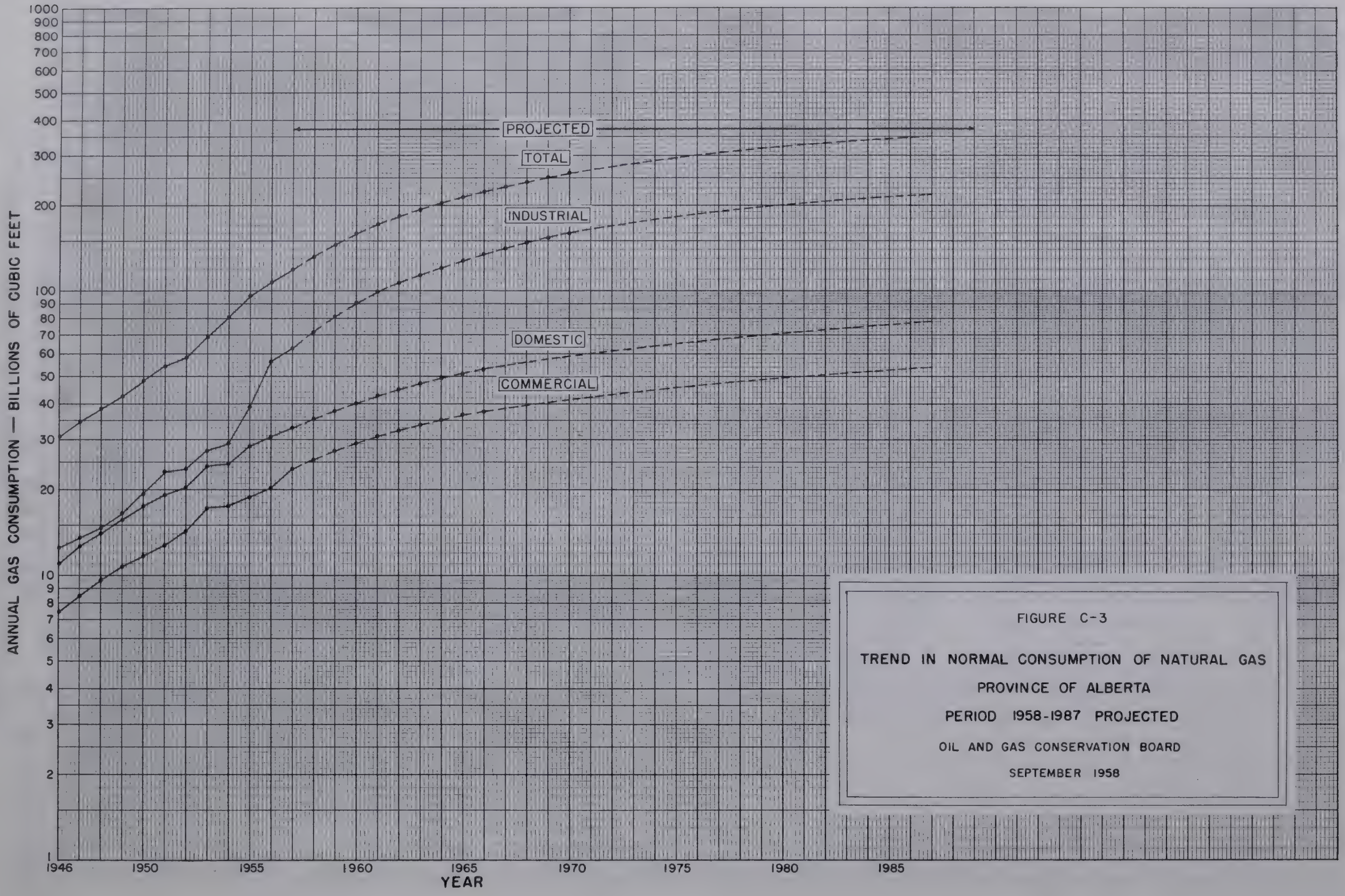


FIGURE C-3

TREND IN NORMAL CONSUMPTION OF NATURAL GAS
PROVINCE OF ALBERTA
PERIOD 1958-1987 PROJECTED
OIL AND GAS CONSERVATION BOARD
SEPTEMBER 1958

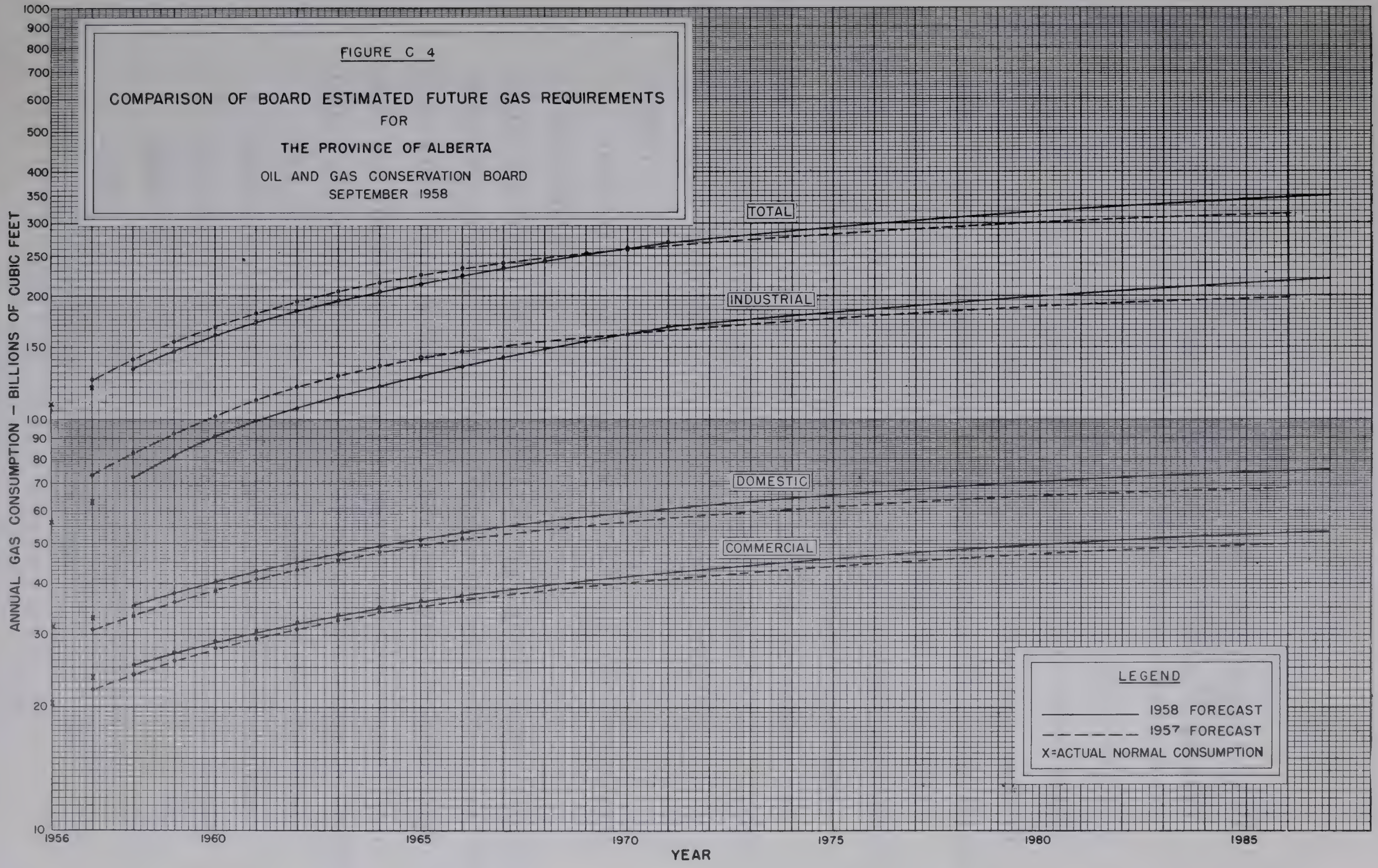


FIGURE C 4

COMPARISON OF BOARD ESTIMATED FUTURE GAS REQUIREMENTS
FOR
THE PROVINCE OF ALBERTA
OIL AND GAS CONSERVATION BOARD
SEPTEMBER 1958

APPENDIX D

THE MEETING OF PRESENT AND FUTURE REQUIREMENTS OF ALBERTA, PRESENT EXPORT COMMITMENTS AND THE PRESENT AND FUTURE REQUIREMENTS OF CANADIAN MARKETS BEYOND ALBERTA

Neither of the applicants indicated in the evidence a complete method by which the requirements of the Province might be met from presently established reserves. Each of them, however, indicated a willingness to sell to any Alberta purchaser volumes of gas required to meet any provincial requirements which could not reasonably be supplied from gas otherwise available in the Province. Alberta and Southern Gas Co. Ltd., has in fact entered into an agreement with Northwestern Utilities, Limited and Canadian Western Natural Gas Company Limited to give contractual effect to such a scheme.

In considering the problem of meeting the requirements of the Province the Board has maintained its policy of excluding from surplus declaration that gas required for full effective protection of the requirements of the Province for a 30-year future period. This has been done in accordance with the provisions of The Gas Resources Preservation Act, 1956. Section 8, subsection (3) of the Act reads as follows:

> "8.(3) The Board shall not grant a permit for the removal of any gas from the Province unless in its opinion it is in the public interest to do so having regard to
>
> (a) the present and future needs of persons within the Province, and

(b) the established reserves and the trends in growth and discovery of reserves of gas in the Province.".

The Board has given somewhat more weight than it has previously done to the trends in growth and discovery of new reserves in the light of the accumulated experience in the Province and its convictions concerning future discoveries. The evidence supporting the development of future reserves is discussed in Appendix B. The Board is firmly of the opinion that full 30-year protection for Alberta can be afforded by

(1) reserving from the established reserves sufficient gas to meet the annual requirements of the Province for a future period of 26 to 30 years, and the peak day requirements for a future period of some 25 years, and

(2) reserving from the future reserves sufficient gas to meet the remaining annual and peak day requirements to the end of the 30th year.

The illustrative deliverability schedules, Tables D-1 to D-5 inclusive, are presented to show how the requirements of the major portion of the Province can be met for the period 1958-1987.

Certain areas of the Province have not been included in the following tabular analyses. These are the Peace River area, the Pakowki Lake area and those areas served by small local utilities. The developments in the Peace River area have been reviewed with respect to the requirements of the area and the previously granted permits of Westcoast Transmission Company Limited and Peace River Transmission Company Limited. There has been insufficient change in the requirements or the total gas reserves of the area to warrant the presentation of new detailed deliverability schedules. In the Pakowki Lake area, all of the reserves of the existing fields, except gas required for local comsumption, have been authorized for export in a permit issued to Canadian Montana Pipeline Company in 1954. Further consideration of this area is not required at this time. While detailed studies of the many areas which are or could be served by small utility companies have not been made, gas reserves suitable for their use have not been considered surplus to provincial requirements.

In preparing the illustrative deliverability schedules the same general procedure used in previous Board reports (1) has been followed. The requirements are shown on the left hand side of the schedules and the volumes of gas which can be obtained from individual fields or composites of fields are listed in succeeding columns. The basic deliverability data for each of the gas fields referred to are listed in Table D-12. Plots of the relationship between the daily delivery capacity and disposable reserves were compiled for each of the fields or composites of fields. These plots

(1) The Petroleum and Natural Gas Conservation Board Reports to The Lieutenant Governor in Council dated January, 1951, March, 1952, November, 1953, May, 1954, and April, 1955.

were then used to determine the ability of the fields to deliver gas to meet peak day requirements as the reserves became depleted. Figure D-1 is a typical plot and is included as an example. It is a plot of the relationship between the delivery capacity and remaining disposable reserves of the Edmonton Deferred Gas Composite both under conditions of maximum development and the minimum development necessary to meet requirements as scheduled in columns 17, 18 and 19 of Table D-2. For fields requiring gas processing plants, deliveries were scheduled at a high load factor and at the maximum rate which could assure a steady load to the plant for a period of approximately fifteen years.

The schedules indicate the surplus and/or residual requirements after deliveries of the volumes of gas from the field listed. At the bottom of the schedules are shown the reserves of the fields or composites available for disposition and the percentages withdrawn during the period of the schedule. Further comments concerning each of the Tables in the Appendix follows.

AREA TRIBUTARY TO THE NORTHWESTERN UTILITIES, LIMITED SYSTEM

The requirements of the area adjacent to the Northwestern Utilities, Limited system are shown in columns 2, 3 and 4 of Table D-2. These include the requirements of the Lloydminster area, which presently are being partially supplied by Northwestern Utilities, Limited.

Oilfield Residue Gas

Columns 5, 6 and 7 of Table D-2 show the projected deliveries of the remaining available gas in the Saskatchewan and Alberta portions of the Lloydminster Field. Columns 8, 9 and 10 indicate the total volumes of oilfield gas in the Edmonton area estimated to be available to meet the requirements of the area. The volumes shown are identical to those in columns 23, 24 and 25 of Table D-1 and are a summation of the deliveries scheduled from the individual fields shown in columns 2 to 22 inclusive of that table. The rates of gas production shown are based on the most recent oil production forecast of the Board.

The British American Oil Company Limited plant at Nevis, processing solution and other gas from the Stettler group of fields, delivers gas to the Canadian Western Natural Gas Company Limited. A portion of the gas is delivered to the Northwestern Utilities, Limited system through an interconnection at Red Deer. Future deliveries from the Stettler composite of fields are assumed to continue to be partly available to the Northwestern Utilities, Limited system and are forecasted in columns 11, 12 and 13 of Table D-2.

Edmonton Area Dry Gas Composite

Columns 14, 15 and 16 of the table illustrate the manner in which deliveries from various dry gas fields adjacent to Edmonton and the Northwestern Utilities, Limited system could be made. The fields comprising this dry gas composite are listed in Table D-12. All of the established reserves totaling some 1,400 Bcf is projected for use by 1984. In that year the fields are capable of peak deliveries of 215 MMcf per day.

Deferred Gas Composite

The fields that constitute the deferred gas composite are also listed in Table D-12. The deliveries from this composite, expected to start in 1972, are forecasted in columns 17, 18 and 19 of Table D-2. The reserve of some 990 Bcf is scheduled for depletion in 1987 with peak day deliveries in that year estimated at 239 MMcf per day.

Remaining Columns of Table D-2

Columns 20, 21 and 22 show deliveries of gas commencing in the year 1978 to the Wabamun - Hinton system to alleviate deficiencies which otherwise would occur. Over a ten year period the deliveries total some 25 Bcf.

After accounting for deliveries from the fields in the manner shown there remains an unsatisfied or residual annual and peak day requirement commencing in the year 1984. The requirement totaling 336 Bcf in the period 1984 to 1987 inclusive is scheduled to be met from future established reserves as depicted in columns 23, 24 and 25. Details of how this may in fact be met from the estimated future reserves appear in Table D-13.

WABAMUN - HINTON AREA

Table D-3 is an illustrative deliverability schedule showing a method of meeting the requirements of the Wabamun - Hinton area. A pipe line connecting the Alexander Field to

Wabamun and Hinton was constructed in 1956 to supply the Calgary Power Company plant at Wabamun and the St. Regis Pulp and Paper mill at Hinton. The portion of the line from the Alexander Field to Wabamun is owned by Mid-Western Industrial Pipelines Limited while the connecting line from Wabamun to Hinton is the property of North Canadian Pipelines Limited. In addition to the two industrial customers, communities along the lines are served. The estimated total requirements of the system are shown in columns 2, 3 and 4 of the table. The sharp reductions in requirements in 1962 is a result of the anticipated conversion of the power plant at Wabamun from gas to coal.

Alexander Composite

The systems are presently being supplied from the Alexander Field only. Other nearby fields include Calahoo, Majeau Lake and Glenevis. It is expected that the entire composite of fields will be depleted by 1962 as shown in columns 5, 6 and 7.

Pine Creek Composite

The Pine Creek composite of fields consisting of Pine Creek, Beaver Creek, Paddle River and Obed fields is shown in columns 8, 9 and 10 to commence deliveries in 1962. An earlier commencement of operation of any of these fields would serve to extend the life of the Alexander composite. A total of 264 Bcf or 77 per cent of the reserves of the Pine Creek composite are shown to be withdrawn by 1987.

Residual Requirements

The residual requirements of the Wabamun - Hinton area after utilizing the Alexander and Pine Creek composites are partially met by deliveries from fields of Table D-2. These could be considered to be from the Windfall field.

Columns 14, 15 and 16 indicate the remaining requirements in the years 1984 to 1987 inclusive. It is assumed that these rather nominal requirements totaling approximately 11 Bcf will be satisfied from additions to present reserves or future discoveries adjacent to the pipe line systems.

THE AREA TRIBUTARY TO THE CANADIAN WESTERN NATURAL GAS COMPANY LIMITED SYSTEM

In its studies of methods of meeting the requirements of the area tributary to the Canadian Western Natural Gas Company Limited system, the Board has in effect merely revised its previously published schedules. Table D-4 shows the method of meeting requirements from those presently known reserves considered most suitable.

Presently Connected Fields - Residual Requirements

Columns 2, 3 and 4 of Table D-4 present the total requirements of the Canadian Western Natural Gas Company Limited system including the line from Penhold to Airdrie but excluding the Town of Brooks which is separately served. That portion of the deliveries of gas from The British American Oil Company Limited plant processing gas from the Stettler composite, expected to be utilized by the Canadian Western system is shown in columns 5, 6 and 7. Deliveries from the Jumping Pound plant and a plant presently being constructed at Okotoks are shown in columns 8 to 13 inclusive. The lower load factors shown for the Jumping Pound plant in the years 1960 to 1962 are to permit 100 per cent load factor operation in the early years of operation of the Okotoks plant in accordance with present understandings. At the end of the 30-year period 441 Bcf or 84 per cent of the available Jumping Pound reserves are scheduled as withdrawn while some 78 Bcf or 59 per cent only of the Okotoks reserves are assumed to have been withdrawn. This is due to the poor deliverability characteristics of the Okotoks Field in relation to its established gas reserves.

Foremost and Bow Island have been scheduled in columns 14, 15, 16 and 17 in the same manner as in previous reports. These fields are used exclusively for storage and peak day supply.

Columns 18, 19 and 20 depict the proposed withdrawals from the Turner Valley Field. These withdrawals are based on a comprehensive study made by the Board in 1954 and are somewhat higher than those predicted in the 1953 report. The load factor has been improved from 51 per cent to 70 per cent as shown in column 20. By the fall of 1958 the Carbon field will be utilized by the Canadian Western system. This field is expected to be used with small annual withdrawals but essentially for peaking purposes until 1970. This is illustrated in columns 21, 22 and 23. After the scheduled withdrawal of some 50 Bcf by 1970, net annual withdrawals are discontinued and the winter withdrawals associated with the peak deliveries are compensated by summer storage.

After the deliveries from the fields which are now connected or are being connected to the Canadian Western system, an unsatisfied or residual requirement as shown in columns 24, 25 and 26 will remain. This is estimated to commence in the year 1963 and totals some 1,295 Bcf over the period 1963 to 1987, with a peak day requirement of 396 MMcf in 1987. Other nearby reserves must be connected to the system to meet these requirements.

Other Possible Sources of Supply

The residual requirements may be met by producing the Calgary, Sarcee and Harmattan-Elkton fields into the Canadian Western system. These fields were selected due to their proximity to the Calgary area, the centre of major consumption. It is assumed the plants required to process the gas in these fields will be sized and that production will be taken so that the plants may operate at full capacity for a period of approximately 15 years before well deliverabilities force declines in throughput.

Calgary Field

The deliveries of gas from the Calgary field shown in columns 27, 28 and 29 are projected in accordance with the plans of Jefferson Lake Petrochemicals of Canada Limited for plant construction in that field. It is expected that the plant will be built in three stages and will process gas from both Crossfield and Elkton formations. The scheduling of the very sour Crossfield formation gas at 85 per cent load factor and the Elkton formation gas at 70 per cent load factor results in the combined load factors shown in column 29.

Sarcee Field

The gas from this field is also sour and will require processing to make it suitable for sale. This gas could be handled by either of the present Jumping Pound or Turner Valley plants or by a separate plant in the Sarcee Field. Deliveries are as illustrated in columns 30, 31 and 32.

Harmattan-Elkton Composite Fields

This composite consists of Harmattan-Elkton, Harmattan East, Sundre and Westward Ho Fields. It has been assumed that the associated gas from this group of fields will be available by 1969. The deferment is necessary in the interests of oil recovery in these fields. A plant will be required to process this gas and might be built in much the same manner as the proposed Calgary plant, i.e. in three increments as shown in columns 33, 34 and 35. Should the gathering and processing of solution gas be economic, deliveries of smaller volumes of gas could commence prior to 1969.

Surplus Gas

Columns 36, 37 and 38 illustrate the quantities of gas available over and above the requirements of the Canadian Western system when the fields of columns 5 to 35 inclusive are produced in the manner shown. It may be seen that the tabulated quantities vary considerably from year to year.

The year to year variation could be eliminated by modifications to the schedule and in any case are beyond the significance of such an illustrative projection. This surplus may therefore be considered equivalent to an average annual surplus of about 30 Bcf with a peak of 95 MMcf per day.

From 1981 (24th year) to 1987 (30th year) the remaining requirements of the Canadian Western Natural Gas Company Limited system are expected to be met by future discoveries in the general area as shown in columns 39, 40 and 41.

MEDICINE HAT AREA

The manner in which the requirements of the Medicine Hat-Redcliff area and the authorized export to Saskatchewan may be met by deliveries from the Etzikom and the Medicine Hat Fields is shown in Table D-5.

The requirements of the Medicine Hat and Redcliff area are depicted in columns 2, 3 and 4. The high load factor shown in column 4 is due to the area being highly industrialized.

Etzikom Field

Columns 5, 6 and 7 illustrate the expected withdrawals from the Etzikom Field. The gas from this field is delivered through South Alberta Pipeline Limited to the City of Medicine Hat and to the fertilizer plant of North West Nitro-Chemicals Limited.

Medicine Hat Field

Columns 8, 9 and 10 show the withdrawals from the Bow Island and Ellis formations located in the south-western portion of the field. Deliveries are shown commencing in 1962.

The amount of gas that is assumed to be produced from the Medicine Hat Sandstone pool in the portion of the field west of range 3 is shown in columns 11, 12 and 13.

In 1957 the Board issued a permit for the export of gas to Saskatchewan Power Corporation from ranges 1, 2 and 3 west of the 4th Meridian in the Medicine Hat Field. The total withdrawal authorized is 207 Bcf as shown in columns 14, 15 and 16. The method of meeting this requirement is assumed to be as shown in columns 17, 18 and 19. Commencing in the year 1981 the Medicine Hat-Redcliff area is expected to have a small residual requirement which will likely be met by deliveries from the eastern portion of the field as shown in columns 17, 18 and 19.

A sizable quantity of gas will still remain in this field after making provisions for the full 30-year requirements of the Medicine Hat-Redcliff area and the present export requirements of Saskatchewan Power Corporation. This surplus could be used by Trans-Canada Pipe Lines Limited to meet part of its additional firm requirements as shown in Table D-7. The method of removal of the surplus could be as shown in columns 20, 21 and 22 of Table D-5.

THE CANADIAN REQUIREMENTS OF TRANS-CANADA PIPE LINES LIMITED

The estimated total Canadian requirements of Trans-Canada Pipe Lines Limited as shown in Table C-4 have been segregated into three portions for the purpose of showing how the requirements can be met from Alberta gas reserves. The requirements have been divided in Table D-8 into those which may be met with gas for which an export permit has been granted, the contractable requirements and the long term requirements. Columns 2, 3 and 4 show the total estimated requirements as detailed in Table C-4. Columns 5, 6 and 7 indicate the portion of the requirements which can be met with gas for which an export permit has been granted. The volumes of gas which are immediately contractable to meet additional requirements are shown in columns 8, 9 and 10. These contractable requirements for Canadian use were arrived at after discussion with officials of Trans-Canada Pipe Lines Limited and represent the additional requirements which the Company either has under contract or for which it will have to contract in the near future to supply new sales contracts. The balance of the requirements, the long term requirements, are those which are expected to occur due to normal market growth, but which are not contractable at the present time. These, shown in columns 11, 12 and 13, commence in 1964 and total some 4,535 Bcf for the remainder of the 25-year period.

Table D-6 is an illustrative deliverability schedule showing how requirements in the amount authorized by the export permit granted to Trans-Canada Pipe Lines Limited in 1954 could be met from the fields authorized for export by the permit. Columns 2, 3 and 4 indicate the volumes of gas presently authorized for export after adjusting by a factor of 1.03 for heating value conversion. This is necessary as the gas quantities referred to in the permit are on an actual Btu basis, while the reserves and deliverability of the fields are on a 1000 Btu basis. Columns 5 to 49 inclusive show the manner in which the Board considers the fields could be effectively utilized. Where the complete reserves of any of these fields is presently under contract to Trans-Canada Pipe Lines Limited, the scheduled withdrawals are in close agreement with the volumes contracted. The volumes of gas scheduled for withdrawal from Homeglen-Rimbey as shown in columns 44, 45 and 46 were based on the assumption that oil operations in the field will require some restriction in gas cap withdrawals until 1965.

The production of the fields in the manner indicated in Table D-6 results in surplus gas being available for the years 1963 to 1980 inclusive. These volumes are shown in columns 50, 51 and 52 as being available for the additional contractable requirements of Trans-Canada as shown in Table D-7.

The additional contractable Canadian gas requirements of Trans-Canada Pipe Lines Limited for the years 1959 to 1983 inclusive are shown in columns 2, 3 and 4 of Table D-7.

Columns 5, 6 and 7 of Table D-7 show the manner in which gas produced from fields already dedicated to Trans-Canada Pipe Lines Limited and surplus to the requirements of the existing permit can be utilized. The volumes are those shown in Columns 50, 51 and 52 of Table D-6. The volumes of gas shown as surplus in columns 20, 21 and 22 of Table D-5 have been included in Table D-7 as columns 8, 9 and 10.

They indicate the manner in which gas produced in ranges 1, 2 and 3 of the Medicine Hat Field could be utilized by Trans-Canada Pipe Lines Limited.

Deliveries of gas to Trans-Canada Pipe Lines Limited from a group of fields generally in the area of the Hussar Field are shown in columns 11, 12 and 13. A large proportion of this gas presently is under contract to Trans-Canada Pipe Lines Limited.

The production of gas from the Westerose South field at the rate of 46 Bcf per year commencing in the fall of 1960 has been postulated in columns 14, 15 and 16. The volumes of gas surplus to the contractable additional requirements of Trans-Canada Pipe Lines Limited when the fields have been scheduled as illustrated are shown in columns 17, 18 and 19. The surplus terminates in the year 1982 and totals 453 Bcf. This amount of gas is surplus to the contractable requirements of Trans-Canada Pipe Lines Limited and to those of the Province and would be available to another exporter of gas. It logically could be assumed to be available from the Westerose South field.

The method of meeting the long term Canadian requirements of Trans-Canada Pipe Lines Limited from future gas reserves is shown in columns 14, 15 and 16 of Table D-13.

ESTABLISHED RESERVES SURPLUS TO THE REQUIREMENTS OF ALBERTA, CANADIAN REQUIREMENTS OF TRANS-CANADA PIPE LINES LIMITED AND OTHER EXPORT COMMITMENTS

Table D-9 is a tabulation of the established gas reserves in the Province, exclusive of the Peace River area, which are surplus to the requirements of Alberta, other Canadian needs and to existing export permits. Excluded also from the tabulation are reserves which have been designated as beyond economic reach in Table A-1. The reserves have been classified as shown in columns 3, 4 and 5 into those which are considered to be within reach of the applicants, those which are deferred beyond 25 years and those which for geographical reasons are considered beyond the reach of the applicants. Of the total of 4,064 Bcf surplus, 3,011 Bcf or 74.1 per cent are considered within reach of the applicants.

The reserves shown in column 3 of Table D-9 have been reclassified in Table D-10 to indicate those volumes of the gas, surplus and within economic reach of the applicants, which each has under contract. Column 1 of Table D-10 indicates the location of the surplus reserve, column 2 the amount of the reserve and columns 3, 4 and 5 the classification by contractual status. Of the 3,011 Bcf surplus reserve considered within economic reach of the applicants, 659 Bcf or 22 per cent is under contract to Westcoast Transmission Company Limited and 1,716 Bcf or 57 per cent is under contract to Alberta and Southern Gas Co. Ltd. The balance, 636 Bcf, was not under contract at the close of the hearings. Certain assumptions had to be made in connection with the volumes of gas shown surplus on Table D-4 and Table D-7. The surplus in the Canadian Western Natural Gas Company Limited schedule, (Table D-4) was considered to exist in fields not now connected to the system, namely Calgary, Sarcee and the Harmattan-Elkton composite. From data submitted at the hearing and other sources, the percentage of reserves under contract to each of the applicants was estimated and the surplus of 372 Bcf prorated as shown. In the case of the Trans-Canada Pipe Lines Limited schedule (Table D-7) it was assumed that all the surplus gas was located in the Westerose South field, 90 per cent of which is under contract to Alberta and Southern. In the case of the balance of the fields the percentages of reserves shown under contract is the Board's interpretation of the evidence submitted at the hearing.

Table D-10 indicates that Westcoast Transmission Company Limited has 51 per cent of its requirements under contract from reserves which are considered surplus and within economic reach of the applicants. The sum of the reserves contracted by Westcoast and those available for contract is 1,295 Bcf or approximately 100 per cent of the applicant's requirements. The corresponding percentages for Alberta and Southern are 41 and 56 respectively. Neither applicant has a commanding percentage of the required reserves under contract at this time.

ILLUSTRATIVE DELIVERABILITY SCHEDULE FOR THE SURPLUS ESTABLISHED RESERVES

As indicated in Table D-10 there was not found to be sufficient surplus gas under contract to satisfy the requirements of either of the applicants. Table D-11 has been prepared to indicate what volumes of gas surplus to Alberta requirements and other commitments could be made available for export from presently established reserves. It is an illustrative deliverability schedule based on production of gas from all sources shown in column 2 of Table D-10 except Garrington and Parkland which are considered to be of a marginal nature. The schedule indicates that the requirements of an export system delivering 115 Bcf per year at a daily maximum rate of 350 MMcf (90 per cent load factor) could be met for an 18 year period before some deficiencies occur.

The fields selected, namely Crossfield, Innisfail, Wimborne, Panther River, Minnehik-Buck Lake, Savanna Creek and Waterton are located generally in a north-south line running through the western part of the Province. The manner in which it is proposed they would be produced is shown in columns 5 to 25 inclusive. Generally the fields, all of which would require processing plants, have been scheduled to operate at full plant capacity for approximately 15 years before field deliverability limitations cause declining rates of output.

It is assumed that the surplus from the Canadian Western and Trans-Canada schedules (Tables D-4 and D-7) which have been combined and shown in columns 26, 27 and 28 of Table D-11 would be available along the route of a pipe line system connecting the individual fields mentioned above. Columns 29, 30 and 31 indicate the residual volumes of gas available after meeting the requirements of an export application in the manner shown.

These surplus volumes totaling some 198 Bcf during the period 1960 to 1977 may be considered available to the requirements of Tables D-4 and D-7 as well as those of Table D-11 through the interrelationship of the schedules previously mentioned.

FUTURE RESERVES SURPLUS TO THE REQUIREMENTS OF ALBERTA, CANADIAN REQUIREMENTS AND OTHER EXPORT COMMITMENTS

The future reserves of some 51 trillion cubic feet estimated in Appendix B provide the necessary further protection for the small remaining Alberta requirements and the long term Canadian requirements of Trans-Canada Pipe Lines Limited. Annual and peak day deliveries consistent with the expected growth of future reserves are presented in columns 2, 3 and 4 of Table D-13. The volumes have been calculated from the tabulation of future reserves referred to in Appendix B assuming a uniform 30-year life for the reserves. This in effect permits delivery of 33.4 billion cubic feet per year over a 30-year period per trillion cubic feet of gas established. The load factor has been arbitrarily selected as 90 per cent to conform generally to that of possible additional export requirements. From April 1, 1958, until the end of 1987 the projection shows that some 30.7 trillion cubic feet of gas will be deliverable from reserves to be developed.

Columns 5 to 13 inclusive of Table D-13 depict the Alberta residual requirements shown in Tables D-2, D-3 and D-4. Columns 14, 15 and 16 show that portion of Trans-

Canada Pipe Lines Limited Canadian requirements which is to be met from future reserves. These correspond to the figures shown in columns 11, 12 and 13 of Table D-8.

After the residual requirements of Alberta and Trans-Canada Pipe Lines Limited are accommodated from future reserves the volumes of gas shown in columns 17, 18 and 19 of Table D-13 will remain. These volumes, which total approximately 25.7 trillion cubic feet, represent gas which is estimated to be deliverable over the period and would be available to meet the requirements of future export applications. The amounts available will be reduced to some extent by reason of some reserves being deferred and others being considered beyond economic reach. It is believed that these will not be significant percentages of the total available reserves.

TABLE D - 1

OIL AND GAS CONSERVATION BOARD

FORECAST OF RESIDUE GAS AVAILABLE FROM OIL FIELDS ADJACENT TO THE EDMONTON AREA

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
YEAR	ACHESON			BONNIE-GLEN-WIZARD LAKE-GLEN PARK			CAMPBELL-NAMAO			LEDUC WOODBEND			PEMBINA			REDWATER			SAMSON			TOTAL OILFIELD GAS COMPOSITE		
	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT
1958	0.8	2.0	110	4.8	37.0	35.6				10.1	30.8	90	4.0	60.0	110	1.3	3.2	110	0.5	2.8	49	21.5	135.8	63
1959	1.1	2.7	110	6.9	37.0	51.1				11.1	33.8	90	24.8	61.8	110	1.9	4.7	110	0.5	2.8	49	46.3	142.8	89
1960	1.3	3.2	110	8.4	37.0	62.3	1.0	2.6	105	10.9	33.2	90	26.2	65.3	110	2.1	5.2	110	0.5	2.8	49	50.4	149.3	93
1961	1.8	4.5	110	12.6	37.0	93.4	1.2	3.1	105	12.2	37.1	90	30.6	76.2	110	2.5	6.2	110	0.5	2.8	49	61.4	166.9	101
1962	1.9	4.7	110	13.1	37.0	97	1.3	3.4	105	12.0	36.5	90	26.3	65.5	110	2.9	7.2	110	0.5	2.8	49	58.0	157.1	101
1963	2.0	5.0	110	13.1	37.0	97	1.4	3.6	105	11.6	35.3	90	26.3	65.5	110	2.9	7.2	110	0.5	2.8	49	57.8	156.4	101
1964	2.2	5.5	110	13.1	37.0	97	1.4	3.6	105	10.9	33.2	90	27.2	67.7	110	2.9	7.2	110	0.5	2.8	49	58.2	157.0	102
1965	2.2	5.5	110	13.1	37.0	97	1.4	3.6	105	14.6	44.5	90	27.7	69.0	110	2.9	7.2	110	0.5	2.8	49	62.4	169.6	101
1966	2.2	5.5	110	13.1	37.0	97	1.6	4.2	105	14.[illegible]	42.9	90	27.7	69.0	110	2.7	6.7	110	0.5	2.8	49	61.9	168.1	101
1967	2.2	5.5	110	13.1	37.0	97	1.8	4.7	105	14.1	42.9	90	25.7	64.0	110	2.7	6.7	110	0.5	2.8	49	60.1	163.6	101
1968	2.2	5.5	110	13.1	37.0	97	1.8	4.7	105	14.3	43.6	90	20.0	49.8	110	2.6	6.5	110	0.5	2.8	49	54.5	149.9	100
1969	2.2	5.5	110	13.1	37.0	97	1.8	4.7	105	13.5	41.1	90	19.2	47.8	110	2.5	6.2	110	0.5	2.8	49	52.8	145.1	100
1970	2.2	5.5	110	13.1	37.0	97	1.8	4.7	105	13.1	44.9	80	14.7	36.6	110	2.4	6.0	110	0.5	2.8	49	47.8	137.5	95
1971	2.2	5.5	110	13.1	37.0	97	1.8	4.7	105	11.7	40.0	80	14.4	35.9	110	2.1	5.2	110	0.5	2.8	49	45.8	131.1	96
1972	2.0	5.0	110	13.1	37.0	97	1.8	4.7	105	10.5	35.9	80	13.7	34.1	110	1.9	4.7	110	0.5	2.8	49	43.5	124.2	96
1973	1.8	4.5	110	13.1	37.0	97	1.8	4.7	105	9.5	32.5	80	12.9	32.1	110	1.6	4.0	110	0.5	2.8	49	41.2	117.6	96
1974	1.6	4.0	110	13.1	37.0	97	1.8	4.7	105	8.5	29.1	80	11.9	29.6	110	1.4	3.5	110	0.5	2.8	49	38.8	110.7	96
1975	1.2	3:0	110	13.1	37.0	97	1.8	4.7	105	7.7	26.3	80	10.7	26.6	110	1.3	3.3	110	0.5	2.8	49	36.3	103.7	96
1976	1.1	2.7	110	13.1	37.0	97	1.8	4.7	105	6.9	23.6	80	8.0	19.9	110	1.1	2.7	110	0.5	2.8	49	32.5	93.4	95
1977	1.0	2.5	110	13.1	37.0	97	1.8	4.7	105	6.1	20.9	80	7.0	17.4	110	1.0	2.5	110	0.5	2.8	49	30.5	87.8	95
1978	0.9	2.2	110	13.1	37.0	97	1.8	4.7	105	5.5	18.8	80	6.1	15.2	110	0.9	2.2	110	0.5	2.8	49	28.8	82.9	95
1979	0.8	2.0	110	13.1	37.0	97	1.8	4.7	105	4.9	16.8	80	4.7	11.7	110	0.7	1.8	110	0.5	2.8	49	26.5	76.8	95
1980	0.7	1.7	110	13.1	37.0	97	1.8	4.7	105	4.3	14.7	82	4.5	11.2	110	0.7	1.8	110				25.1	71.1	96
1981	0.6	1.5	110	13.1	37.0	97	1.8	4.7	105	4.3	14.7	82	4.3	10.7	110							24.1	68.6	96
1982	0.5	1.2	110	13.1	37.0	97	1.6	4.2	105	4.3	14.7	82	4.1	10.2	110							23.6	67.3	96
1983	0.5	1.2	110	13.1	37.0	97	1.5	3.9	105	1.7	5.8	80	3.8	9.5	110							20.6	57.4	98
1984	0.4	1.0	110	13.1	37.0	97	1.3	3.4	105				3.6	9.0	110							18.4	50.4	100
1985	0.4	1.0	110	13.1	37.0	97	1.2	3.1	105				3.4	8.5	110							18.1	49.6	100
1986				13.1	37.0	97	1.0	2.7	105				3.3	8.2	110							17.4	47.9	100
1987				13.1	37.0	97	0.9	2.3	105				3.1	7.7	110							17.1	47.0	100
TOTAL	40.0			373.3			43.8			248.4			419.9			45.0			11.0			1181.4		
WASTE PRIOR TO PLANT COMPLETION							1.2						20.0											
ESTABLISHED RESERVES AVAILABLE FOR DISPOSAL	40.0			435.0			45.0			292.0			460.0			45.0			11.0					
PERCENT WITHDRAWN	100.0			85.9			100.0			85.1			95.7			100.0			100.0					

TABLE D - 2

OIL AND GAS CONSERVATION BOARD

ILLUSTRATIVE DELIVERABILITY SCHEDULE FOR THE AREA TRIBUTARY TO THE NORTHWESTERN UTILITIES LIMITED SYSTEM

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
	TOTAL REQUIREMENTS			LLOYDMINSTER*			OILFIELD GAS COMPOSITE			STETTLER COMPOSITE			EDMONTON DRY GAS COMPOSITE			DEFERRED GAS COMPOSITE			AVAILABLE FOR REQUIREMENTS OF TABLE D-3			DELIVERIES FROM FUTURE RESERVES		
YEAR	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT
1958	66.1	383.3	47	1.2	8.3	40	21.5	135.8	63	1.8	3.9	126	41.6	235.3	49									
1959	72.6	412.5	48	1.2	8.5	39	46.3	142.8	89	2.1	5.2	111	23.0	256.0	25									
1960	79.3	442.0	49	1.0	7.0	39	50.4	149.3	93	2.6	9.7	73	25.3	276.0	25									
1961	86.9	474.6	50	1.0	6.6	42	61.4	166.9	101	3.4	15.5	60	21.1	285.6	20									
1962	91.9	493.2	51	0.9	6.2	40	58.0	157.1	101	4.1	21.3	53	28.9	308.6	26									
1963	97.0	520.7	51	0.8	5.7	38	57.8	156.4	101	4.8	27.1	49	33.6	331.5	28									
1964	102.5	549.0	51	0.7	5.0	38	58.2	157.0	102	5.5	33.0	46	38.1	354.0	30									
1965	107.9	578.4	51	0.7	4.4	44	62.4	169.6	101	6.2	38.8	44	38.6	365.6	29									
1966	112.7	604.8	51	0.6	3.8	43	61.9	168.1	101	6.9	44.6	42	43.3	388.3	31									
1967	117.4	629.3	51	0.5	3.3	42	60.1	163.6	101	7.6	50.4	41	49.2	412.0	33									
1968	121.9	654.0	51	0.5	3.0	46	54.5	149.9	100	8.3	56.2	40	58.6	444.9	36									
1969	127.1	681.6	51	0.4	2.6	42	52.8	145.1	100	8.2	53.3	42	65.7	480.6	38									
1970	132.2	709.1	51	0.2	1.1	50	47.8	137.5	95	7.7	46.9	45	76.5	523.6	40									
1971	137.4	737.0	51				45.8	131.1	96	6.5	38.2	47	77.6	517.7	41	7.5	50.0	41						
1972	139.8	736.0	52				43.5	124.2	96	5.5	30.3	50	83.0	531.5	43	7.8	50.0	43						
1973	141.8	746.0	52				41.2	117.6	96	4.8	24.6	54	79.9	503.8	44	15.9	100.0	44						
1974	144.2	759.0	52				38.8	110.7	96	4.0	17.8	62	85.3	530.5	44	16.1	100.0	44						
1975	146.7	772.0	52				36.3	103.7	96	3.4	12.6	74	74.3	455.7	45	32.7	200.0	45						
1976	149.2	785.0	52				32.5	93.4	95	2.9	8.2	97	80.4	483.4	46	33.4	200.0	46						
1977	152.0	800.0	52				30.5	87.8	95				60.8	356.1	47	60.7	356.1	47						
1978	154.6	814.0	52				28.8	82.9	95				42.1	244.9	47	84.3	488.3	47	0.6	2.1	78			
1979	157.1	827.0	52				26.5	76.8	95				44.0	251.9	48	88.0	503.3	48	1.4	5.0	77			
1980	159.7	841.0	52				25.1	71.1	96				45.6	259.6	48	91.1	517.8	48	2.1	7.5	77			
1981	162.4	855.0	52				24.1	68.6	96				47.0	265.9	49	94.1	530.5	49	2.8	10.0	77			
1982	164.9	868.0	52				23.6	67.3	96				48.2	270.3	49	96.4	542.3	49	3.3	11.9	76			
1983	167.7	883.0	52				20.6	57.4	98				53.1	306.9	49	98.0	533.0	48	4.0	14.3	77			
1984	170.6	898.0	52				18.4	50.4	100				39.1	215.0	50	89.0	490.0	50	3.4	12.2	76	27.5	154.8	49
1985	173.5	913.0	52				18.1	49.6	100							72.1	400.0	50	2.2	7.9	76	85.5	471.3	50
1986	176.4	929.0	52				17.4	47.9	100							59.0	324.0	50	2.5	9.1	75	102.5	566.2	50
1987	179.3	944.0	52				17.1	47.0	100							43.8	239.0	50	2.2	7.9	76	120.6	665.9	50
TOTAL	3983.1			9.7			1181.4			96.3			1403.9			989.9			24.5			336.1		
ESTABLISHED RESERVES AVAILABLE FOR DISPOSITION				9.7			1328.0			209.8			1403.9			989.9								
PERCENT WITHDRAWN				100%			88.9			45.9			100			100								

* INCLUDES DELIVERIES FROM SASKATCHEWAN PORTION OF FIELD

TABLE D - 3

OIL AND GAS CONSERVATION BOARD

ILLUSTRATIVE DELIVERABILITY SCHEDULE TO MEET THE REQUIREMENTS OF THE WABAMUN-HINTON AREA

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
YEAR	WABAMUN-HINTON AREA			ALEXANDER COMPOSITE			PINE CREEK COMPOSITE			FIELDS OF TABLE D-2			DELIVERIES FROM FUTURE RESERVES		
	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT
1958	11.9	41.7	78	11.9	41.7	78									
1959	16.1	54.5	81	16.1	54.5	81									
1960	17.8	59.9	81	17.8	59.9	81									
1961	15.5	53.2	80	15.5	53.2	80									
1962	9.6	34.4	77	6.7	24.0	77	2.9	10.4	77						
1963	10.0	35.9	76				10.0	35.9	76						
1964	10.2	36.5	77				10.2	36.5	77						
1965	10.4	37.3	76				10.4	37.3	76						
1966	10.7	38.4	76				10.7	38.4	76						
1967	10.9	39.2	76				10.9	39.2	76						
1968	11.1	39.8	76				11.1	39.8	76						
1969	11.3	40.6	76				11.3	40.6	76						
1970	11.6	41.6	77				11.6	41.6	77						
1971	11.8	42.3	77				11.8	42.3	77						
1972	11.8	42.3	77				11.8	42.3	77						
1973	12.1	43.6	76				12.1	43.6	76						
1974	12.1	43.6	76				12.1	43.6	76						
1975	12.1	43.6	76				12.1	43.6	76						
1976	12.2	43.8	76				12.2	43.8	76						
1977	12.2	43.9	76				12.2	43.9	76						
1978	12.2	43.9	76				11.6	41.8	76	0.6	2.1	76			
1979	12.4	44.5	76				11.0	39.5	76	1.4	5.0	76			
1980	12.5	44.9	76				10.4	37.4	76	2.1	7.5	76			
1981	12.6	45.1	76				9.8	35.1	76	2.8	10.0	76			
1982	12.6	45.2	76				9.3	33.3	76	3.3	11.9	76			
1983	12.7	45.6	76				8.7	31.3	76	4.0	14.3	76			
1984	12.8	46.0	76				8.2	29.5	76	3.4	12.2	76	1.2	4.3	76
1985	12.9	46.5	76				7.8	28.1	76	2.2	7.9	76	2.9	10.5	76
1986	13.1	47.4	76				7.3	26.4	76	2.5	9.1	76	3.3	11.9	76
1987	13.1	47.4	76				6.9	25.0	76	2.2	7.9	76	4.0	14.5	76
TOTAL	368.3			68.0			264.4			24.5			11.4		
ESTABLISHED RESERVES AVAILABLE FOR DISPOSAL				68.0			344.0								
PERCENT WITHDRAWN				100.0			76.9								

TABLE D - 4

OIL AND GAS CONSERVATION BOARD

ILLUSTRATIVE DELIVERABILITY SCHEDULE TO MEET REQUIREMENTS OF CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

1	2	3	4	5	6	7	8	8	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41
YEAR	TOTAL REQUIREMENTS			STETTLER COMPOSITE			JUMPING POUND			OKOTOKS			FOREMOST			BOW ISLAND	TURNER VALLEY			CARBON			RESIDUAL REQUIREMENTS			CALGARY			SARCEE			HARMATTAN-ELKTON			SURPLUS			TO BE MET FROM FUTURE RESERVES		
	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	PEAK DAY MMCFD	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT
1958	40.0	267	41	0.8	6.9	33	20.9	81.6	70				0.2	12.7	4	45.0	17.9	108.1	45	0.2	12.7	43																		
1959	43.5	291	41	0.9	7.3	33	21.6	81.6	73	2.0	10.8	50	0.2	12.6	4	45.1	16.8	108.1	44	2.0	25.5	21																		
1960	47.1	314	41	1.1	9.0	33	19.7	81.6	66	3.9	10.8	100	0.2	12.6	4	45.1	19.8	108.1	50	2.4	46.8	14				20.5	74.0	76							20.5	74.0	76			
1961	51.3	335	42	1.3	10.8	33	19.7	81.6	66	3.9	10.8	100	0.2	12.6	4	45.2	22.2	103.7	59	4.0	70.3	16				20.5	74.0	76							20.5	74.0	76			
1962	54.4	355	42	1.5	12.5	33	20.3	81.6	68	3.3	10.8	85	0.2	12.5	4	45.3	24.1	103.7	64	5.0	88.6	15				20.5	74.0	76							20.5	74.0	76			
1963	57.2	373	42	1.7	14.1	33	20.8	81.6	70	3.3	10.8	85	0.2	12.4	4	45.5	24.8	97.0	70	5.0	106.1	13	1.4	5.5	70	20.5	74.0	76	2.6	10.0	70				21.7	78.5	76			
1964	60.0	390	42	1.9	15.8	33	20.8	81.6	70	3.3	10.8	85	0.2	12.3	4	45.6	24.8	97.0	70	5.0	111.2	12	4.0	15.7	70	25.4	90.0	77	3.8	15.0	70				25.2	89.3	77			
1965	63.1	412	42	2.1	17.4	33	20.8	81.6	70	3.3	10.8	85	0.2	12.2	4	45.7	24.8	97.0	70	5.0	120.3	11	6.9	27.0	70	25.4	90.0	77	3.8	15.0	70				22.3	78.0	78			
1966	65.6	418	43	2.3	19.1	33	20.7	81.0	70	3.3	10.6	85	0.2	12.1	4	45.8	24.5	96.0	70	5.0	115.8	12	9.6	37.6	70	25.4	90.0	77	3.8	15.0	70				19.6	67.4	80			
1967	68.3	435	43	2.5	20.8	33	19.6	76.7	70	3.2	10.3	85	0.2	12.0	5	45.9	24.5	96.0	70	5.0	120.2	11	13.3	52.1	70	25.4	90.0	77	3.8	15.0	70				15.9	52.9	82			
1968	70.7	449	43	2.7	22.4	33	18.6	72.8	70	3.1	10.0	85	0.2	12.0	5	45.9	23.6	92.4	70	5.0	125.0	11	17.5	68.5	70	25.4	90.0	77	3.8	15.0	70				11.7	36.5	88			
1969	73.1	466	43	2.9	24.1	33	17.7	69.3	70	3.0	9.7	85	0.2	11.9	5	46.0	19.5	76.4	70	3.7	126.4	8	26.1	102.2	70	25.4	90.0	77	3.8	15.0	70	2.5	60.0	70	5.6	64.8	24			
1970	76.0	484	43	3.1	25.7	33	16.8	65.8	70	2.9	9.5	85	0.2	11.8	5	46.1	16.2	63.5	70	2.0	125.4	4	34.8	136.2	70	30.4	106.0	79	3.8	15.0	70	15.3	60.0	70	14.7	44.8	90			
1971	78.5	489	44	3.3	27.4	33	15.9	62.2	70	2.9	9.3	85	0.2	11.7	5	46.2	14.1	55.1	70	STORAGE	112.3		42.1	164.8	70	30.4	106.0	79	3.8	15.0	70	25.6	100.0	70	17.7	56.2	86			
1972	79.8	496	44	3.5	29.1	33	15.1	59.1	70	2.8	9.0	85	0.2	11.6	5	46.3	12.2	47.8	70		113.1		46.0	180.0	70	30.4	106.0	79	3.8	15.0	70	25.6	100.0	70	13.8	39.0	97			
1973	81.5	507	44	3.7	30.7	33	14.3	56.0	70	2.7	8.7	85	0.2	11.5	5	46.4	10.4	40.7	70		116.5		50.2	196.5	70	30.4	106.0	79	3.8	15.0	70	25.6	100.0	70	9.6	24.5	107			
1974	82.8	516	44	4.0	33.2	33	13.6	53.2	70	2.6	8.4	85	0.2	11.4	5	46.5	8.7	34.0	70		119.1		53.7	210.2	70	30.4	106.0	79	3.8	15.0	70	48.5	190.0	70	29.0	100.8	79			
1975	84.1	524	44	4.2	34.9	33	12.9	50.5	70	2.5	8.0	85	0.2	11.3	5	46.7	7.2	28.2	70		120.9		57.1	223.5	70	30.4	106.0	79	3.8	15.0	70	48.5	190.0	70	25.6	87.5	80			
1976	85.5	519	45	4.4	36.5	33	12.2	47.7	70	2.5	8.0	85	0.2	11.3	5	46.8	6.0	23.5	70		109.6		60.2	235.6	70	30.4	106.0	79	3.8	15.0	70	48.5	190.0	70	22.5	75.4	82			
1977	87.0	530	45	4.6	38.2	33	11.6	45.4	70	2.4	7.7	85	0.2	11.3	5	46.8	5.0	19.6	70		113.6		63.2	247.4	70	30.4	106.0	79	3.3	12.9	70	48.5	190.0	70	19.0	61.5	85			
1978	88.6	539	45	3.8	31.5	33	11.0	43.1	70	2.4	7.7	85	0.2	11.2	5	46.9	4.1	16.0	70		120.0		67.1	262.6	70	30.4	106.0	79	3.1	12.1	70	48.5	190.0	70	14.9	45.5	90			
1979	90.0	548	45	3.5	29.1	33	10.4	40.7	70	2.3	7.4	85	0.2	11.1	5	47.0	3.1	12.1	70		120.0		70.5	280.6	69	30.4	106.0	79	2.9	11.4	70	48.5	190.0	70	11.3	26.8	115			
1980	91.6	556	45	3.2	26.5	33	9.9	38.7	70	2.2	7.1	85	0.2	11.0	5	47.1	2.0	7.8	70		120.0		74.1	297.8	68	30.1	105.1	79	2.8	11.0	70	48.5	190.0	70	7.3	8.3	241			
1981	93.2	567	45	2.9	24.1	33	9.4	36.8	70	2.2	7.1	85	0.2	10.9	5	47.2	1.0	3.9	70		120.0		77.5	317.0	67	29.3	102.5	79	2.6	10.2	70	48.5	190.0	70	2.9				14.3	
1982	94.6	576	45	2.7	22.5	33	8.9	34.8	70	2.1	6.8	85	0.2	10.8	5	47.3					120.0		80.7	333.8	66	28.6	100.2	79	2.5	9.8	70	48.5	190.0	70				1.1	33.8	9
1983	96.5	588	45	2.5	20.7	33	8.5	33.3	70	2.1	6.7	85	0.2	10.7	5	47.4					125.0		83.2	344.2	66	27.4	96.2	78	2.4	9.4	70	48.5	190.0	70				4.9	48.6	28
1984	98.0	595	45	2.3	19.1	33	8.0	31.3	70	2.0	6.4	85	0.2	10.6	5	47.5					125.0		85.5	355.1	66	26.0	91.3	78	2.2	8.6	70	48.5	190.0	70				8.8	65.2	37
1985	99.7	607	45	2.1	17.4	33	7.6	29.7	70	2.0	6.4	85	0.2	10.5	5	47.6					125.0		87.8	370.4	65	24.5	86.0	78	2.1	8.2	70	46.5	182.0	70				14.7	94.2	43
1986	101.3	617	45	1.9	15.8	33	7.2	28.2	70	1.9	6.1	85	0.2	10.4	5	47.7					125.0		90.1	383.8	64	23.2	81.4	78	2.0	7.8	70	43.0	168.2	70				21.9	126.4	47
1987	103.0	627	45	1.8	15.0	33	6.9	27.0	70	1.9	6.1	85	0.2	10.3	5	47.9					125.0		92.2	395.7	64	22.2	77.8	78	1.9	7.4	70	40.3	158.0	70				27.8	152.5	50
TOTAL	2306.0			79.2			441.4			78.0			6.0				357.3			49.3			1294.8			749.7			79.8			757.9			371.8			79.2		
WASTE PRIOR TO PLANT COMPLETION																																98.0								
ESTABLISHED RESERVES AVAILABLE FOR DISPOSITION				209.8			525.0			132.0			20				379.1			246.3						1039.0			103.0			1241.0								
PERCENT WITHDRAWN				38.7			84.2			59.1			30.0				94.1			19.9						72.1			77.5			61.1								

TABLE D - 5

OIL AND GAS CONSERVATION BOARD

ILLUSTRATIVE DELIVERABILITY SCHEDULE TO MEET REQUIREMENTS OF THE MEDICINE HAT-REDCLIFF AREA AND SASKATCHEWAN POWER CORPORATION

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
YEAR	MEDICINE HAT REQUIREMENTS			ETZIKOM			BOW ISLAND AND ELLIS COMPOSITE OF MEDICINE HAT FIELD			WESTERN PORTION OF THE MEDICINE HAT FIELD			SASKATCHEWAN POWER CORPORATION REQUIREMENTS			DELIVERIES FROM EASTERN PORTION OF MEDICINE HAT FIELD - RANGES 1. 2 AND 3			SURPLUS FROM EASTERN PORTION OF THE MEDICINE HAT FIELD		
	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT
																To SASKATCHEWAN POWER CORPORATION					
1958	12.5	49.4	69	3.6	10.4	95				8.9	39.0	63	4.5	29.5	42	4.5	29.5	42			
1959	13.0	51.3	70	3.9	11.3	95				9.1	40.0	62	5.3	31.4	46	5.3	31.4	46			
1960	13.3	52.3	70	4.1	11.8	95				9.2	40.5	62	5.7	35.2	44	5.7	35.2	44	7.7	30.0	70
1961	13.8	54.1	70	4.4	12.5	96				9.4	41.6	62	6.5	38.0	47	6.5	38.0	47	7.7	30.0	70
1962	14.1	55.1	70	4.6	13.1	96	0.9	6.0	41	8.6	36.0	65	7.4	43.7	46	7.4	43.7	46	7.7	30.0	70
1963	14.5	57.0	70	6.3	18.0	96	0.9	6.0	41	7.3	33.0	61	8.3	48.5	47	8.3	48.5	47	7.7	30.0	70
1964	14.9	57.9	70	6.5	18.5	96	0.9	6.0	41	7.5	33.4	62	9.1	53.2	47	9.1	53.2	47	7.7	30.0	70
1965	15.4	59.8	70	6.7	19.1	96	0.9	6.0	41	7.8	34.7	62	10.0	57.0	48	10.0	57.0	48	7.7	30.0	70
1966	15.7	61.8	70	6.7	19.1	96	0.9	6.0	41	8.1	36.7	60	11.0	62.7	48	11.0	62.7	48	7.7	30.0	70
1967	16.1	62.7	70	6.7	19.1	96	0.9	6.0	41	8.5	37.6	62	11.7	66.5	48	11.7	66.5	48	7.7	30.0	70
1968	16.5	64.6	70	6.7	19.1	96	0.9	6.0	41	8.9	39.5	62	12.2	69.4	48	12.2	69.4	48	7.7	30.0	70
1969	16.9	66.5	70	6.7	19.1	96	0.9	6.0	41	9.3	41.4	62	12.6	73.2	47	12.6	73.2	47	7.1	27.8	70
1970	17.3	67.5	70	6.7	19.1	96	0.9	6.0	41	9.7	42.4	63	13.1	77.0	47	13.1	77.0	47	5.4	21.1	70
1971	17.7	69.3	70	6.7	19.1	96	0.9	6.0	41	10.1	44.2	63	13.7	78.9	48	13.7	78.9	48	4.5	17.6	70
1972	18.1	71.2	70	4.0	11.9	92	0.9	6.0	41	13.2	53.3	68	14.2	78.9	49	14.2	78.9	49	3.8	14.9	70
1973	18.4	72.2	70	4.0	11.9	92	0.9	6.0	41	13.5	54.3	68	14.7	78.9	51	14.7	78.9	51	3.3	12.9	70
1974	19.0	74.1	70	4.0	11.9	92	0.9	6.0	41	14.1	56.2	69	15.3	78.9	53	15.3	78.9	53	2.8	11.0	70
1975	19.5	76.0	70	4.0	11.9	92	0.8	5.4	41	14.7	58.7	69	15.8	78.9	55	15.8	78.9	55	2.1	8.2	70
1976	19.7	77.0	70	4.0	11.9	92	0.8	5.4	41	14.9	59.7	68	16.3	78.9	57	16.3	78.9	57	1.4	5.5	70
1977	20.3	79.8	70	4.0	11.9	92	0.7	4.7	41	15.6	63.2	68							21.1	82.6	70
1978	20.6	80.8	70	3.4	10.1	92	0.7	4.7	41	16.5	66.0	68							20.5	80.2	70
1979	21.0	81.7	70	1.3	3.9	92	0.6	4.0	41	19.1	73.8	71							19.8	78.4	70
1980	21.5	84.6	70				0.6	4.0	41	20.9	80.6	71				To MEDICINE HAT			19.2	75.1	70
1981	21.9	85.5	70				0.5	3.3	41	20.7	79.5	71				0.7	2.7	71.0	17.9	70.1	70
1982	22.4	87.4	70				0.5	3.3	41	19.6	75.2	71				2.3	8.9	70.9	15.7	61.5	70
1983	22.8	89.3	70				0.5	3.3	41	18.4	71.0	71				3.9	15.0	71.2	13.6	53.4	70
1984	23.3	91.2	70				0.4	2.7	41	17.5	67.8	71				5.4	20.7	71.5	11.6	45.8	70
1985	23.8	94.0	70				0.4	2.7	41	16.5	64.3	70				6.9	27.0	70.0	9.5	37.1	70
1986	24.3	95.0	70				0.4	2.7	41	15.6	61.0	71				8.1	31.3	70.9	7.8	30.8	70
1987	25.0	97.8	70				0.4	2.7	41	14.9	57.6	71				9.7	37.5	70.8	5.7	22.7	70
TOTAL	553.3			109.0			19.0			388.3			207.4			244.4			262.1		
ESTABLISHED RESERVES AVAILABLE FOR DISPOSITION				109.0			19.0			489.5						793.3			793.3		
PERCENT WITHDRAWN				100.0			100.0			79.3						30.8			33.0		

TABLE D - 6

OIL AND GAS CONSERVATION BOARD

ILLUSTRATIVE DELIVERABILITY SCHEDULE TO MEET TRANS-CANADA PIPE LINES LIMITED PERMIT REQUIREMENTS

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52
YEAR	TRANS-CANADA PERMIT			PROVOST			BINDLOSS			ATLEE-BUFFALO			CESSFORD			SIBBALD			PRINCESS			PINCHER CREEK			OYEN			NEVIS			KESSLER			COUNTESS-DUCHESS			GILBY			HOMEGLEN-RIMBEY			HAMILTON LAKE			SYLVAN LAKE			AVAILABLE FOR REQUIREMENTS OF TABLE D-7		
	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER-CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT
1958	27.6	288.4	26	11.7	47.2	68	3.0	12.1	68	0.4	6.1	90	5.7	106.1	90	0.4	4.1	90	0.6	7.0	90	5.8	105.8	90																											
1959	100.9	402.7	69	20.0	70.3	74	3.0	11.1	74	2.0	7.4	74	30.9	118.6	74	1.1	4.1	74	2.3	8.5	74	39.0	144.9	74	0.6	2.2	74	2.0	35.6	90																					
1960	138.1	502.8	75	22.8	70.3	89	4.0	12.8	86	2.6	8.3	86	42.8	135.7	86	1.1	4.1	86	2.3	8.5	86	45.9	145.6	86	0.6	2.2	86	11.7	37.3	86	0.2	3.0	90	0.3	5.5	90	0.6	11.0	90	3.2	58.5	90									
1961	168.9	564.4	82	22.8	70.3	82	5.0	16.9	81	3.0	10.1	81	46.8	155.0	81	1.2	4.1	81	2.5	8.5	81	47.0	167.4	77	0.6	2.0	81	13.0	50.4	81	1.0	3.0	81	2.0	6.8	81	4.0	13.5	81	20.0	60.9	82									
1962	200.0	638.6	86	22.8	70.3	82	11.5	35.0	87	3.3	10.5	87	46.8	155.0	87	1.4	4.4	87	8.2	26.3	89	59.1	180.0	87	0.7	2.2	87	15.5	60.0	87	1.1	3.5	87	2.1	6.7	87	4.2	13.5	87	20.0	60.9	87	1.5	4.8	87	1.8	5.5	87			
1963	210.1	638.6	90	23.1	70.3	90	11.5	35.0	90	4.9	15.0	90	50.9	155.0	90	1.6	4.9	90	10.0	30.4	90	59.1	180.0	90	0.9	2.6	90	19.7	60.0	90	2.0	6.1	90	2.8	8.6	90	9.0	27.4	90	20.0	60.9	90	1.7	5.2	90	1.8	5.5	90	8.9	28.3	86
1964	210.1	638.6	90	23.1	70.3	90	11.5	35.0	90	4.9	15.0	90	50.9	155.0	90	1.6	4.9	90	10.0	30.4	90	59.1	180.0	90	0.9	2.6	90	19.7	60.0	90	2.0	6.1	90	2.8	8.6	90	9.0	27.4	90	20.0	60.9	90	1.7	5.2	90	1.8	5.5	90	8.9	28.3	86
1965	210.1	638.6	90	23.1	70.3	90	11.5	35.0	90	4.9	15.0	90	50.9	155.0	90	1.6	4.9	90	10.0	30.4	90	59.1	180.0	90	0.9	2.6	90	19.7	60.0	90	2.0	6.1	90	2.8	8.6	90	9.0	27.4	90	39.4	120.0	90	1.7	5.2	90	1.8	5.5	90	28.3	87.4	89
1966	210.1	638.6	90	23.1	70.3	90	11.5	35.0	90	4.9	15.0	90	50.9	155.0	90	1.6	4.9	90	10.0	30.4	90	59.1	180.0	90	0.9	2.6	90	19.7	60.0	90	2.0	6.1	90	2.8	8.6	90	9.0	27.4	90	39.4	120.0	90	1.7	5.2	90	1.8	5.5	90	28.3	87.4	89
1967	210.1	638.6	90	23.1	70.3	90	11.5	35.0	90	4.9	15.0	90	50.9	155.0	90	1.6	4.9	90	10.0	30.4	90	59.1	180.0	90	0.9	2.6	90	19.7	60.0	90	2.0	6.1	90	2.8	8.6	90	9.0	27.4	90	39.4	120.0	90	1.7	5.2	90	1.8	5.5	90	28.3	87.4	89
1968	210.1	638.6	90	23.1	70.3	90	11.5	35.0	90	4.9	15.0	90	50.9	155.0	90	1.6	4.9	90	10.0	30.4	90	59.1	180.0	90	0.9	2.6	90	19.7	60.0	90	2.0	6.1	90	2.8	8.6	90	9.0	27.4	90	39.4	120.0	90	1.7	5.2	90	1.8	5.5	90	28.3	87.4	89
1969	210.1	638.6	90	23.1	70.3	90	11.5	35.0	90	4.9	15.0	90	50.9	155.0	90	1.6	4.9	90	10.0	30.4	90	59.1	180.0	90	0.9	2.6	90	19.7	60.0	90	2.0	6.1	90	2.8	8.6	90	9.0	27.4	90	39.4	120.0	90	1.7	5.2	90	1.8	5.5	90	28.3	87.4	89
1970	210.1	638.6	90	23.1	70.3	90	11.5	35.0	90	4.9	15.0	90	50.9	155.0	90	1.6	4.9	90	10.0	30.4	90	59.1	180.0	90	0.9	2.6	90	19.7	60.0	90	2.0	6.1	90	2.8	8.6	90	9.0	27.4	90	39.4	120.0	90	1.7	5.2	90	1.8	5.5	90	28.3	87.4	89
1971	210.1	638.6	90	23.1	70.3	90	11.5	35.0	90	4.9	15.0	90	50.9	155.0	90	1.6	4.9	90	10.0	30.4	90	59.1	180.0	90	0.9	2.6	90	19.7	60.0	90	2.0	6.1	90	2.8	8.6	90	9.0	27.4	90	39.4	120.0	90	1.7	5.2	90	1.8	5.5	90	28.3	87.4	89
1972	210.1	638.6	90	23.1	70.3	90	11.5	35.0	90	4.9	15.0	90	50.9	155.0	90	1.6	4.9	90	10.0	30.4	90	59.1	180.0	90	0.7	2.1	90	19.7	60.0	90	2.0	6.1	90	2.8	8.6	90	9.0	27.4	90	39.4	120.0	90	1.7	5.2	90	1.8	5.5	90	28.1	86.9	88
1973	210.1	638.6	90	23.1	70.3	90	11.5	35.0	90	4.9	15.0	90	50.9	155.0	90	1.6	4.9	90	10.0	30.4	90	59.1	180.0	90	0.6	1.8	90	19.7	60.0	90	2.0	6.1	90	2.8	8.6	90	9.0	27.4	90	39.4	120.0	90	1.7	5.2	90	1.8	5.5	90	28.0	86.6	89
1974	210.1	638.6	90	23.1	70.3	90	11.5	35.0	90	4.9	15.0	90	50.9	155.0	90	1.6	4.9	90	10.0	30.4	90	59.1	180.0	90				19.7	60.0	90	2.0	6.1	90	2.8	8.6	90	9.0	27.4	90	39.4	120.0	90	1.7	5.2	90	1.8	5.5	90	27.4	84.8	88
1975	210.1	638.6	90	23.1	70.3	90	11.5	35.0	90	4.9	15.0	90	50.9	155.0	90	1.6	4.9	90	10.0	30.4	90	56.4	171.7	90				19.7	60.0	90	2.0	6.1	90	2.5	7.6	90	9.0	27.4	90	39.4	120.0	90	1.7	5.2	90	1.8	5.5	90	24.4	75.5	88
1976	210.1	638.6	90	23.1	70.3	90	11.5	35.0	90	4.9	15.0	90	50.9	155.0	90	1.6	4.9	90	10.0	30.4	90	53.7	163.5	90				19.7	60.0	90	2.0	6.1	90	2.4	7.3	90	9.0	27.4	90	39.4	120.0	90	1.7	5.2	90	1.8	5.5	90	21.6	67.0	88
1977	210.1	638.6	90	23.1	70.3	90	11.5	35.0	90	4.9	15.0	90	50.9	155.0	90	1.6	4.9	90	10.0	30.4	90	51.2	155.9	90				19.7	60.0	90	2.0	6.1	90	2.4	7.3	90	9.0	27.4	90	39.4	120.0	90	1.7	5.2	90	1.8	5.5	90	19.1	59.4	88
1978	210.1	638.6	90	23.1	70.3	90	11.5	35.0	90	4.9	15.0	90	50.9	155.0	90	1.6	4.9	90	10.0	30.4	90	48.8	148.6	90				19.7	60.0	90	2.0	6.1	90	2.2	6.7	90	9.0	27.4	90	39.4	120.0	90	1.7	5.2	90	1.8	5.5	90	16.5	51.5	88
1979	210.1	638.6	90	23.1	70.3	90	10.4	31.7	90	4.9	15.0	90	50.9	155.0	90	1.6	4.9	90	9.6	29.2	90	46.5	141.6	90				19.7	60.0	90	2.0	6.1	90	2.1	6.4	90	9.0	27.4	90	39.4	120.0	90	1.7	5.2	90	1.8	5.5	90	12.6	39.7	87
1980	210.1	638.6	90	20.7	63.0	90	9.4	28.6	90	4.9	15.0	90	50.7	154.3	90	1.6	4.9	90	8.2	24.9	90	44.3	134.9	90				19.7	60.0	90	2.0	6.1	90	2.0	6.1	90	8.5	25.9	90	39.4	120.0	90	1.7	5.2	90	1.8	5.5	90	4.8	15.8	83
1981	60.2	638.6	90	5.4	57.5	90	2.5	26.2	90	1.4	15.0	90				0.5	4.9	90	2.3	20.0	90	11.5	122.0	90				5.6	59.2	90	0.5	6.1	90	0.5	6.0	90	2.4	25.3	90	11.3	120.0	90	0.5	5.2	90	0.5	5.5	90			
TOTAL	4480.5			518.9			232.8			100.9			1089.0			34.5			196.0			1218.4			11.9			402.4			38.8			52.1			172.7			724.9			32.6			34.7			398.4		
ESTABLISHED RESERVES AVAILABLE FOR DISPOSITION				541.0			279.0			133.0			1089.0			39.0			199.0			1800.0			12.0			534.0			49.0			67.0			237.0			816.0			41.0			52.0					
PERCENT WITHDRAWN				96.0			86.4			75.9			100.0			88.5			98.4			67.5			99.2			75.3			79.2			77.8			72.9			88.9			79.5			66.8					

TABLE D - 7

OIL AND GAS CONSERVATION BOARD

ILLUSTRATIVE DELIVERABILITY SCHEDULE TO MEET TRANS-CANADA ADDITIONAL CONTRACTABLE REQUIREMENTS

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
YEAR	REQUIREMENTS			SURPLUS FROM TABLE D - 6			MEDICINE HAT SURPLUS			DRY GAS COMPOSITE			WESTEROSE SOUTH			SURPLUS		
	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT
1958																		
1959	3.1	55.6	90							3.1	55.6	85						
1960	20.6	97.9	90				7.7	30.0	70	12.9	37.8	85	7.7	60.1	35	7.7	30.0	70
1961	36.4	175.1	90				7.7	30.0	70	10.1	35.1	85	46.0	140.0	90	27.4	30.0	25
1962	60.3	226.6	90				7.7	30.0	70	11.5	79.6	85	46.0	140.0	90	4.9	24.0	56
1963	74.2	226.6	90	8.9	28.3	86	7.7	30.0	70	25.4	79.6	85	46.0	140.0	90	13.8	51.3	74
1964	74.2	226.6	90	8.9	28.3	86	7.7	30.0	70	25.5	79.9	85	46.0	140.0	90	13.9	51.6	74
1965	74.2	226.6	90	28.3	87.4	89	7.7	30.0	70	15.5	49.9	85	46.0	140.0	90	23.3	80.7	79
1966	74.2	226.6	90	28.3	87.4	89	7.7	30.0	70	15.5	49.9	85	46.0	140.0	90	23.3	80.7	79
1967	74.2	226.6	90	28.3	87.4	89	7.7	30.0	70	15.6	50.1	85	46.0	140.0	90	23.4	80.9	79
1968	74.2	226.6	90	28.3	87.4	89	7.7	30.0	70	15.6	50.1	85	46.0	140.0	90	23.4	80.9	79
1969	74.2	226.6	90	28.3	87.4	89	7.1	27.8	70	15.6	50.1	85	46.0	140.0	90	22.8	78.7	79
1970	74.2	226.6	90	28.3	87.4	89	5.4	21.1	70	15.7	50.1	85	46.0	140.0	90	21.2	72.0	81
1971	74.2	226.6	90	28.3	87.4	89	4.5	17.6	70	15.7	50.1	85	46.0	140.0	90	20.3	68.5	81
1972	74.2	226.6	90	28.1	86.9	88	3.8	14.9	70	15.7	50.1	85	46.0	140.0	90	19.4	65.3	81
1973	74.2	226.6	90	28.0	86.6	89	3.3	12.9	70	15.8	50.3	85	46.0	140.0	90	18.9	63.2	82
1974	74.2	226.6	90	27.4	84.8	88	2.8	11.0	70	15.8	50.3	85	46.0	140.0	90	17.8	59.5	82
1975	74.2	226.6	90	24.4	75.5	88	2.1	8.2	70	15.8	50.3	85	46.0	140.0	90	14.1	47.4	81
1976	74.2	226.6	90	21.6	67.0	88	1.4	5.5	70	15.9	50.6	85	46.0	140.0	90	10.7	36.5	80
1977	74.2	226.6	90	19.1	59.4	88	21.1	82.6	70	15.9	50.6	85	46.0	140.0	90	27.9	106.0	72
1978	74.2	226.6	90	16.5	51.5	88	20.5	80.2	70	15.9	50.6	85	46.0	140.0	90	24.7	95.7	71
1979	74.2	226.6	90	12.6	39.7	87	19.8	78.4	69	15.9	50.6	85	46.0	140.0	90	20.1	82.1	67
1980	74.2	226.6	90	4.8	15.8	83	19.2	75.1	70	15.6	47.5	85	46.0	140.0	90	11.4	51.8	60
1981				-15.3	-165.7		17.9	70.1	70	14.0	42.6	85	46.0	140.0	90	62.6	87.0	20
TOTAL	1456.0			383.1			198.2			354.0			973.7			453.0		
ESTABLISHED RESERVES AVAILABLE FOR DISPOSITION										434.0			1178.0					
PER CENT DEPLETED										81.5			82.7					

TABLE D - 8

OIL AND GAS CONSERVATION BOARD

CLASSIFICATION OF TRANS-CANADA PIPE LINES LIMITED CANADIAN REQUIREMENTS

1	2	3	4	5	6	7	8	9	10	11	12	13
YEAR	TRANS-CANADA TOTAL CANADIAN REQUIREMENTS			REQUIREMENTS FROM EXISTING PERMIT			ADDITIONAL CONTRACTABLE REQUIREMENTS			REQUIREMENTS TO BE MET FROM FUTURE RESERVES		
	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT
1958	26.8	280.0	26	26.8	280	26						
1959	101.1	451.6	61	98.0	396	69	3.1	55.6	15			
1960	154.6	586.9	72	134.0	489	75	20.6	97.9	58			
1961	200.4	723.1	77	164.0	548	82	36.4	175.1	58			
1962	254.3	846.6	83	194.0	620	86	60.3	226.6	73			
1963	278.2	846.6	90	204.0	620	90	74.2	226.6	90			
1964	303.0	922	90	204.0	620	90	74.2	226.6	90	24.8	75.4	90
1965	330.0	1004	90	204.0	620	90	74.2	226.6	90	51.8	157.4	90
1966	358.0	1090	90	204.0	620	90	74.2	226.6	90	79.8	243.4	90
1967	382.0	1162	90	204.0	620	90	74.2	226.6	90	103.8	315.4	90
1968	409.0	1245	90	204.0	620	90	74.2	226.6	90	130.8	398.4	90
1969	417.0	1268	90	204.0	620	90	74.2	226.6	90	138.8	421.4	90
1970	433.0	1320	90	204.0	620	90	74.2	226.6	90	154.8	473.4	90
1971	454.0	1382	90	204.0	620	90	74.2	226.6	90	175.8	535.4	90
1972	470.0	1430	90	204.0	620	90	74.2	226.6	90	191.8	583.4	90
1973	488.0	1487	90	204.0	620	90	74.2	226.6	90	209.8	640.4	90
1974	506.0	1540	90	204.0	620	90	74.2	226.6	90	227.8	693.4	90
1975	525.0	1598	90	204.0	620	90	74.2	226.6	90	246.8	751.4	90
1976	544.0	1657	90	204.0	620	90	74.2	226.6	90	265.8	810.4	90
1977	564.0	1720	90	204.0	620	90	74.2	226.6	90	285.8	873.4	90
1978	585.0	1780	90	204.0	620	90	74.2	226.6	90	306.8	933.4	90
1979	606.0	1845	90	204.0	620	90	74.2	226.6	90	327.8	998.4	90
1980	627.0	1908	90	204.0	620	90	74.2	226.6	90	348.8	1061.4	90
1981	649.0	1976	90	58.4	620	90				590.6	1356.0	90
1982	673.0	2050	90							673.0	2050.0	90
TOTAL	10338.4			4347.2			1456.0			4535.2		

TABLE D - 9

OIL AND GAS CONSERVATION BOARD

ESTABLISHED GAS RESERVES* SURPLUS TO ALBERTA, OTHER CANADIAN NEEDS AND EXISTING PERMITS

(1) FIELD, POOL	(2) TOTAL SURPLUS RESERVES BCF	(3) RESERVES CONSIDERED WITHIN REACH OF APPLICANTS, BCF	(4) DEFERRED RESERVES BCF	(5) RESERVES CONSIDERED BEYOND REACH OF APPLICANTS, BCF	(6) REMARKS
1. FIELDS OF TABLE D-4(1)	372	372			(1) SURPLUS GAS MARKETABLE WITHIN 25 YEAR PERIOD.
2. FIELDS OF TABLE D-7(2)	453	453			(2) SURPLUS GAS MARKETABLE WITHIN 25 YEAR PERIOD.
3. ANTELOPE	12			12	
4. BONNIE GLEN ASSOCIATED	406		406		
5. CASTOR	20			20	
6. CONNERSVILLE	19			19	
7. CONTROL	20			20	
8. CROSSFIELD	189	189			
9. ENCHANT	11			11	
10. GARRINGTON	40	40			
11. GHOST PINE	15			15	
12 GOLDEN SPIKE	126		126		
13. GRASSY ISLAND LAKE	20			20	
14. HILDA	14			14	
15. INNISFAIL	80	80			
16. DUHAMEL	14			14	
17. MALMO	19			19	
18. NEW NORWAY	11			11	
19. MAZEPPA	16			16	
20. MINNIHEK-BUCK LAKE	291	291			
21. PANTHER RIVER	116	116			
22. PARKLAND	20	20			
23. ROLLING HILLS	26			26	
24. SAVANNA CREEK	539	539			
25. TURIN	28			28	
26. WATERTON	742	742			
27. WEST DRUMHELLER	32			32	
28. WIMBORNE	169	169			
29. RESERVES LESS THAN 10 BCF	244			244	
TOTAL	4064	3011	532	521	
PER CENT	100	74.1	13.1	12.8	

* EXCLUSIVE OF PEACE RIVER AREA AND RESERVES BEYOND ECONOMIC REACH.

TABLE D - 10

OIL AND GAS CONSERVATION BOARD

ESTABLISHED GAS RESERVES, SURPLUS TO ALBERTA AND CANADA AND WITHIN REACH OF APPLICANTS

(1)	(2)	(3)	(4)	(5)	(6)
		RESERVES CONTRACTED TO			
FIELD, POOL OR SCHEDULE	TOTAL SURPLUS RESERVES BCF	WESTCOAST BCF	ALBERTA & SOUTHERN BCF	RESERVES NOT UNDER CONTRACT BCF	REMARKS
Fields of Table D-4	372(1)	120(3)	14(4)	238	
Fields of Table D-7	453(2)		408(5)	45	Assume all gas from Westerose South
Crossfield	189		189		
Garrington	40			40	
Innisfail	80			80	
Minnihek-Buck Lake	291		227	64	
Panther River	116		116		
Parkland	20		20		
Savanna Creek	539	539			
Waterton	742		742		
Wimborne	169			169	
Total	3011	659	1716	636	
Applicant's Requirements		1300	4200		
Per cent Applicant's Requirements Surplus and Contracted For		51	41		
Total Contracted to Applicant and Open for Contract		1295	2352		
Per cent of Applicant's Requirements		100	56		
Total Surplus		3011	3011		
Per cent of Applicant's Requirements		232	72		

(1) Marketable gas over 25 year period, see Table D-4.
(2) Marketable gas over 25 year period, see Table D-7.
(3) Taken as 32.4 per cent.
(4) Taken as 3.8 per cent.
(5) Taken as 90 per cent.

TABLE D - 11

OIL AND GAS CONSERVATION BOARD

ILLUSTRATIVE DELIVERABILITY SCHEDULE FOR THE SURPLUS ESTABLISHED RESERVES

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34
YEAR	TOTAL DELIVERIES			CROSSFIELD			INNISFAIL			WIMBORNE			PANTHER RIVER			MINNEHIK-BUCK LAKE			SAVANNA CREEK			WATERTON			SURPLUS FROM TRANS-CANADA AND CANADIAN WESTERN NATURAL GAS			SURPLUS			DEFICIENCIES TO BE MET FROM FUTURE RESERVES		
	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT
1960	19.2	350	90	1.7	30.0	90	0.5	7.0	110				0.7	12.0	90	2.5	45.0	90	3.3	60.0	90	5.5	100.0	90	28.2	104.0	74	23.2	8.0				
1961	115.0	350	90	9.9	30.0	90	2.8	7.0	110				3.9	12.0	90	14.8	45.0	90	19.7	60.0	90	32.9	100.0	90	47.9	104.0	127	16.9	8.0				
1962	115.0	350	90	9.9	30.0	90	2.8	7.0	110				3.9	12.0	90	14.8	45.0	90	19.7	60.0	90	32.9	100.0	90	25.4	98.0	71	-5.6	2.0				
1963	115.0	350	90	9.9	30.0	90	2.8	7.0	110				3.9	12.0	90	14.8	45.0	90	19.7	60.0	90	32.9	100.0	90	35.5	129.8	75	4.5	33.8	36			
1964	115.0	350	90	9.9	30.0	90	2.7	6.7	110				3.9	12.0	90	14.8	45.0	90	19.7	60.0	90	32.9	100.0	90	39.1	140.9	76	8.0	44.6	49			
1965	115.0	350	90	9.9	30.0	90	2.7	6.7	110	10.0	30.0	90	3.9	12.0	90	14.8	45.0	90	19.7	60.0	90	32.9	100.0	90	45.6	158.7	79	24.5	92.4	72			
1966	115.0	350	90	9.9	30.0	90	2.7	6.7	110	10.0	30.0	90	3.9	12.0	90	14.8	45.0	90	19.7	60.0	90	32.9	100.0	90	42.9	148.1	79	21.8	81.8	73			
1967	115.0	350	90	9.9	30.0	90	2.6	6.5	110	10.0	30.0	90	3.9	12.0	90	14.8	45.0	90	19.7	60.0	90	32.9	100.0	90	39.3	133.8	81	18.1	67.3	74			
1968	115.0	350	90	9.9	30.0	90	2.6	6.5	110	10.0	30.0	90	3.9	12.0	90	14.8	45.0	90	19.7	60.0	90	32.9	100.0	90	35.1	117.4	82	13.9	50.9	75			
1965	115.0	350	90	9.9	30.0	90	2.6	6.5	110	10.0	30.0	90	3.9	12.0	90	14.8	45.0	90	19.7	60.0	90	32.9	100.0	90	28.4	143.5	54	7.2	77.0	26			
1970	115.0	350	90	9.9	30.0	90	2.5	6.5	105	10.0	30.0	90	3.9	12.0	90	14.8	45.0	90	19.7	60.0	90	32.9	100.0	90	35.9	116.8	84	14.6	50.3	80			
1971	115.0	350	90	9.9	30.0	90	2.5	6.5	105	10.0	30.0	90	3.9	12.0	90	14.8	45.0	90	19.7	60.0	90	32.9	100.0	90	38.0	124.7	83	16.7	58.2	79			
1972	115.0	350	90	9.9	30.0	90	2.5	6.5	105	10.0	30.0	90	3.9	12.0	90	14.8	45.0	90	19.7	60.0	90	32.9	100.0	90	33.2	104.3	87	11.9	37.8	86			
1973	115.0	350	90	9.3	28.3	90	2.4	6.3	105	10.0	30.0	90	3.9	12.0	90	14.8	45.0	90	19.7	60.0	90	32.9	100.0	90	28.5	87.7	89	6.5	19.3	92			
1974	115.0	350	90	8.3	25.2	90	2.4	6.3	105	10.0	30.0	90	3.8	11.6	90	14.8	45.0	90	19.7	60.0	90	32.9	100.0	90	46.8	160.3	80	23.7	88.4	73			
1975	115.0	350	90	7.4	22.6	90	2.4	6.3	105	10.0	30.0	90	3.6	11.0	90	14.8	45.0	90	19.7	60.0	90	32.9	100.0	90	39.7	134.9	81	15.5	59.8	71			
1976	115.0	350	90	6.7	20.4	90	2.3	6.0	105	10.0	30.0	90	3.5	10.7	90	14.2	43.2	90	19.1	58.2	90	32.5	99.0	90	33.2	111.9	81	6.5	29.4	61			
1977	115.0	350	90	6.0	18.3	90	2.3	6.0	105	10.0	30.0	90	3.3	10.1	90	12.1	36.8	90	17.9	54.6	90	29.2	89.0	90	46.9	167.5	77	12.7	62.3	56			
1978	115.0	350	90	5.4	16.5	90	2.3	6.0	105	10.0	30.0	90	3.1	9.5	90	10.3	31.4	90	16.7	50.8	90	26.3	80.2	90	39.6	141.2	77		15.6		1.3		
1979	115.0	350	90	4.8	14.6	90	2.1	5.5	105	10.0	30.0	90	3.0	9.1	90	8.8	26.8	90	15.7	47.8	90	23.7	72.2	90	31.4	108.9	79				15.5	35.1	121
1980	115.0	350	90	4.3	13.1	90	2.1	5.5	105	7.0	21.0	90	2.8	8.6	90	7.5	22.8	90	14.7	44.8	90	21.3	64.9	90	18.7	60.1	85				36.6	109.2	92
1981	115.0	350	90	3.9	11.9	90	2.1	5.5	105	4.0	12.0	90	2.7	8.2	90	6.4	19.5	90	13.7	41.7	90	19.2	58.5	90	65.5	87.0	206	2.5				105.7	
1982	115.0	350	90	3.5	10.7	90	2.0	5.2	105	3.0	9.0	90	2.6	7.9	90	5.2	15.8	90	12.9	39.3	90	17.3	52.7	90							68.5	209.4	90
1983	115.0	350	90	3.1	9.4	90	2.0	5.2	105				2.4	7.3	90				12.0	36.5	90	15.6	47.5	90							79.9	244.1	90
1984	115.0	350	90	2.8	8.5	90	2.0	5.2	105				2.3	7.0	90				11.3	34.4	90	14.0	42.7	90							82.6	252.2	90
1985	95.8	350	90	2.1	7.6	90	1.4	4.9	105				1.8	6.7	90				8.8	32.3	90	10.5	38.4	90							71.2	260.1	75
TOTAL	2875.0			188.1			60.1			164.0			86.3			289.0			441.6			708.6			824.8			243.1			355.6		
WASTE PRIOR TO PLANT COMPLETION							6.0			5.0																							
ESTABLISHED RESERVES AVAILABLE FOR DISPOSITION				189.0			80.0			169.0			116.0			289.0			539.0			742.0											
PER CENT WITHDRAWN				99.5			82.6			100.0			74.0			100.0			82.0			95.5											

(1) FIELD, POOL OR SCHEDULE
FIELDS OF TABLE D-4
FIELDS OF TABLE D-7
CROSSFIELD
GARRINGTON
INNISFAIL
MINNIHEK-BUCK LAKE
PANTHER RIVER
PARKLAND
SAVANNA CREEK
WATERTON
WIMBORNE
TOTAL
APPLICANT'S REQUIREMENTS
PER CENT APPLICANT'S REQUIREMENTS SURPLUS AND CONTRACTED FOR
TOTAL CONTRACTED TO APPLICANT AND OPEN FOR CONTRACT
PER CENT OF APPLICANT'S REQUIREMEN
TOTAL SURPLUS
PER CENT OF APPLICANT'S REQUIREMEN

TABLE D - 12

OIL AND GAS CONSERVATION BOARD

BASIC DELIVERABILITY DATA FOR FIELDS OF TABLES D-2, D-3, D-4, D-5, D-6, D-7 AND D-11

1 NAME OF FIELD	2 ZONE	3 PRESENT NO. OF WELLS	4 ESTIMATED NO. OF WELLS (FIELD FULLY DEVELOPED)	5 INITIAL DELIVERY CAPACITY DISPOSABLE GAS (FIELD FULLY DEVELOPED) MMCFD
Edmonton Dry Gas Composite				
Beaverhill Lake	Viking	12	25	88.8
Fairydell-Bon Accord	Viking	20	30	250.3
	Basal Quartz	0	6	6.4
Fort Saskatchewan	Viking	22	25	327.0
Morinville	Viking	0	2	3.4
	Basal Blairmore	22	26	64.4
St. Albert	Basal Blairmore	7	8	39.3
Westlock	Viking	15	80	562.0
Viking Kinsella	Viking	104	150	302.2
	Basal Blairmore	1	2	9.0
	Devonian	1	2	2.2
Small Fields		58	82	247.9
Total Edmonton Dry Gas Composite		262	446	1902.9
Edmonton Deferred Gas Composite				
Blueridge	Detrital	1	1	6.9
	Mississippian	2	2	5.7
Carson Creek	Beaverhille Lake	1	1	20.4
Excelsior	Viking	0	8	22.1
	Basal Blairmore	2	20	65.0
Goodwin Lake	Viking	0	2	1.7
	Nordegg	1	2	1.4
Joarcam	Viking	0	15	29.1
Leduc Woodbend	Leduc	0	100	1007.0
Pigeon Lake	Leduc	1	1	7.3
Westerose	Leduc	0	10	146.0
Windfall	Leduc	8	13	235.8
Total Edmonton Deferred Gas Composite		16	175	1548.4
Alexander Composite				
Alexander	Basal Quartz	10	10	225.9
Calahoo	Basal Blairmore	2	2	12.6
Glenevis	Glauconite	0	2	1.4
Majeau Lake	Glauconite	1	1	1.8
	Rundle	0	1	3.8
Total Alexander Composite		13	16	245.5
Pine Creek Composite				
Beaver Creek	Wabamun	1	1	4.7
Obed	Rundle	1	1	1.7
Paddle River	Jurassic	4	5	1.9
	Mississippian	0	1	6.3
Pine Creek	Leduc	4	5	65.5
Total Pine Creek Composite		10	13	80.1
Jumping Pound	Rundle	11	15	122.1
Okotoks	Wabamun	8	12	12.9
Carbon	Lower Cretaceous	6	20	145.6
Calgary	Mississippian	3	15	133.4
	Wabamun	8	41	89.7
Sarcee	Mississippian	2	4	24.7
Harmattan-Elkton Composite				
Harmattan-Elkton	Mississippian	10	32	333.8
Harmattan East	Mississippian	2	6	26.7
Sundre	Mississippian	0	3	15.5
Westward Ho	Mississippian	0	2	1.6
Total Harmattan-Elkton Composite		12	43	377.6
Etzikom	Bow Island	7	23	60.5

1 NAME OF FIELD	2 ZONE	3 PRESENT NO. OF WELLS	4 ESTIMATED NO. OF WELLS (FIELD FULLY DEVELOPED)	5 INITIAL DELIVERY CAPACITY DISPOSABLE GAS (FIELD FULLY DEVELOPED) MMCFD
Medicine Hat Composite				
Medicine Hat	Bow Island	2	5	7.6
	Ellis	2	2	4.9
Total Medicine Hat Composite		4	7	12.5
Medicine Hat East	Medicine Hat	53	445	123.5
Medicine Hat West	Medicine Hat	118	369	139.8
Provost	Viking	57	150	261.6
Bindloss	Viking	20	50	100.4
	Basal Blairmore	1	3	3.6
Atlee Buffalo	Viking	11	18	23.6
	Basal Blairmore	2	15	15.1
Cessford	Viking	3	25	21.3
	Basal Colorado	32	120	616.6
	Basal Blairmore	10	30	68.0
Sibbald	Viking	8	10	17.8
	Basal Blairmore	2	3	0.9
Princess	Bow Island	2	2	1.9
	Basal Colorado	7	12	29.2
	Sunburst	7	13	69.0
	Rundle	3	6	8.2
	Jefferson	1	5	7.6
Pincher Creek	Rundle	9	20	316.6
Oyen	Viking	3	4	9.4
Nevis	Lower Cretaceous and Devonian	6	47	175.7
Kessler	Viking	11	30	72.6
Countess	Bow Island	5	9	8.1
Duchess	Bow Island	1	2	0.8
	Basal Colorado	2	3	7.1
Gilby	Detrital	0	4	6.0
	Mississippian	2	18	70.5
Homeglen Rimbey	Leduc	24	50	725.0
Hamilton Lake	Viking	2	10	13.0
Sylvan Lake	Basal Quartz	3	3	10.6
	Mississippian	1	1	3.0
Westerose South	Leduc	3	6	702.9
Trans-Canada Dry Gas Composite				
Hussar	Basal Colorado	6	37	24.0
	Glauconite	17	21	33.7
Lone Pine Creek	Wabamun	1	1	
Lone Pine Creek West	Wabamun	1	1	
Olds	Wabamun	4	8	17.6
Three Hills Creek	Mississippian	4	7	13.6
Wayne	Viking	0	6	9.2
	Basal Blairmore	2	2	6.7
Wildunn Creek	Viking	3	8	12.6
Rosebud	Viking	4	4	12.3
	Glauconite	5	5	24.3
	Basal Blairmore	1	1	3.4
Total Trans-Canada Dry Gas Composite		48	101	157.4
Crossfield	Mississippian	2	12	74.1
Wimborne	Leduc	14	23	194.7
Panther River	Nisku	1	4	20.5
Minnehik-Buck Lake	Mississippian	3	27	169.1
Savanna Creek	Mississippian	6	12	124.0
Waterton	Mississippian	5	64	278.0

TABLE D- 13

OIL AND GAS CONSERVATION BOARD

ILLUSTRATIVE DELIVERABILITY SCHEDULE TO MEET ALBERTA AND OTHER CANADIAN REQUIREMENTS FROM FUTURE RESERVES

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
YEAR	DELIVERIES FROM FUTURE RESERVES			TABLE D-2 RESIDUAL REQUIREMENTS			TABLE D -3 RESIDUAL REQUIREMENTS			TABLE D-4 RESIDUAL REQUIREMENTS			TABLE D-8 RESIDUAL REQUIREMENTS			FUTURE RESERVES AVAILABLE FOR DISPOSITION		
	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT	ANNUAL BCF	PEAK DAY MMCFD	LOAD FACTOR PER CENT
1958	53.5	163	90													53.5	163.0	90
1959	127.0	386	90													127.0	386.0	90
1960	200.5	610	90													200.5	610.0	90
1961	274.0	834	90													274.0	834.0	90
1962	347.5	1058	90													374.5	1058.0	90
1963	421.0	1280	90													421.0	1280.0	90
1964	494.5	1503	90										24.8	75.4	90	469.7	1427.6	90
1965	571.3	1739	90										51.8	157.4	90	519.5	1581.6	90
1966	651.5	1982	90										79.8	243.4	90	571.7	1738.6	90
1967	735.0	2235	90										103.8	315.4	90	631.2	1919.6	90
1968	815.2	2480	90										130.8	398.4	90	684.4	2081.6	90
1969	892.0	2710	90										138.8	421.4	90	753.2	2288.6	90
1970	965.5	2938	90										154.8	473.4	90	810.7	2464.6	90
1971	1035.7	3150	90										175.8	535.4	90	859.9	2614.6	90
1972	1102.5	3355	90										191.8	583.4	90	910.7	2771.6	90
1973	1166.0	3540	90										209.8	640.4	90	956.2	2899.6	90
1974	1226.1	3730	90										227.8	693.4	90	998.3	3036.6	90
1975	1279.6	3890	90										246.8	751.4	90	1032.8	3138.6	90
1976	1326.3	4035	90										265.8	810.4	90	1060.5	3224.6	90
1977	1369.7	4170	90										285.8	873.4	90	1083.9	3296.6	90
1978	1413.1	4300	90										306.8	933.4	90	1106.3	3366.6	90
1979	1453.2	4425	90										327.8	998.4	90	1125.4	3426.6	90
1980	1490.0	4535	90										348.8	1061.4	90	1141.2	3473.6	90
1981	1523.4	4630	90								14.3		590.6	1356.0	90	932.8	3259.7	90
1982	1556.8	4730	90							1.1	33.8	9	673.0	2050.0	90	882.7	2646.2	91
1983	1586.8	4830	90							4.9	48.6	28				1581.9	4781.4	91
1984	1616.8	4920	90	27.5	154.8	49	1.2	4.3	77	8.8	65.2	37				1579.3	4695.7	92
1985	1643.5	5000	90	85.5	471.3	50	2.9	10.5	76	14.7	94.2	43				1540.4	4424.0	95
1986	1666.9	5070	90	102.5	566.2	50	3.3	11.9	76	21.9	126.4	47				1539.2	4365.5	96
1987	1686.9	5130	90	120.6	665.9	50	4.0	14.5	76	27.8	152.5	50				1534.5	4297.1	98
TOTAL	30691.8			336.1			11.4			79.2			4535.2			25729.9		

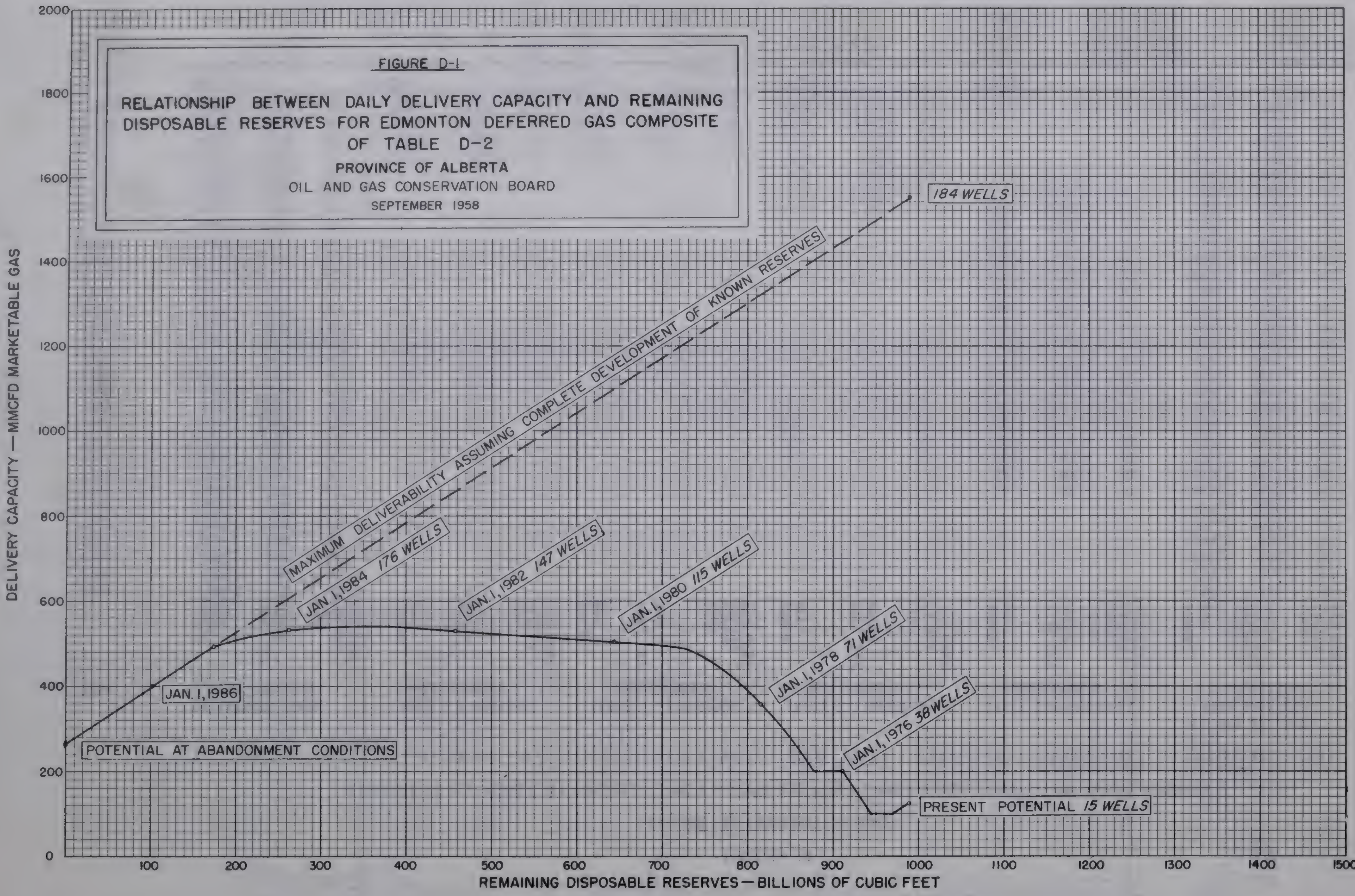


FIGURE D-1

RELATIONSHIP BETWEEN DAILY DELIVERY CAPACITY AND REMAINING DISPOSABLE RESERVES FOR EDMONTON DEFERRED GAS COMPOSITE OF TABLE D-2

PROVINCE OF ALBERTA
OIL AND GAS CONSERVATION BOARD
SEPTEMBER 1958

APPENDIX E

AN ALTERNATIVE ANALYSIS OF THE FUTURE REQUIREMENTS OF ALBERTA, OTHER CANADIAN MARKETS AND THE RESERVES REQUIRED TO MEET THEM AND OTHER EXPORT COMMITMENTS

In the interests of simplifying the analysis of future requirements and the manner in which they may be met the Board has developed an alternative "formula" procedure. This procedure has been tested against the more detailed method of future requirement projection and deliverability schedule analysis and, while giving slightly different answers, it is considered a suitable alternative. It is much easier and less time consuming to apply. It may be particularly suitable for the consideration of future Canadian requirements by both Federal and Provincial authorities.

The method involves four steps briefly described as follows:

(1) The cumulative future annual requirements of a market area for a desired future period are estimated from a known initial requirement by assuming an effective or average annual growth rate.

(2) The peak day requirement of the terminal year of the desired future period is estimated from the initial annual requirement by assuming an appropriate load factor and the effective annual growth rate employed in step (1).

(3) The remaining reserve required to deliver gas at the peak rate determined in step (2) is estimated having regard to the average reserve-deliverability ratio

for the type of field constituting the source.

(4) The total reserve needed to satisfy the future requirements, both as to annual and as to peak day needs, is the sum of the cumulative annual requirement (step 1) and the required remaining reserve (step 3).

The method may be applied separately to individual areas and the results totalled. It may also be applied separately for different periods of years to permit a comparison of the reserves needed for varying degrees of protection against both established and estimated future reserves. The details of the method and its application to the situation dealt with in this report follows.

Cumulative Future Annual Requirements

Let A_1 be the known annual requirement of the first or present year and let g be the effective annual growth rate in per cent per year. Then the annual requirement for the i^{th} year,

$$A_i = A_1(g/100)^{i-1}$$

and the cumulative future annual requirement for n years

$$\overset{n}{\underset{1}{A}} = A_1\sum_{i=1}^{i=n}(g/100)^{i-1} = A_1S$$

The summation factor, $\sum_{i=1}^{i=n}(g/100)^{i-1}$, designated as S, depends only upon n, the number of future years, and g, the growth rate. It may readily be evaluated by binomial expansion and summation for any selected values of n and g. An evaluation of the summation factor appears in Figure E-1 for n values from 20 to 30 years and for growth rates, g, from

0 to 7 per cent per year. To illustrate the use of Figure E-1, the 30 year cumulative annual future requirement of a market growing at an effective rate of 4.4 per cent per year is 60 times its first year requirement or just double what it would have been had it been static.

Future Peak Day Requirement

In any year the peak day requirement of a market, P_i, is related to the annual requirement, A_i, through the load factor X_i.

Thus $P_i = A_i/365X_i$, and in the n^{th} year

$$P_n = A_n/365X_n = (A_1/365X_n)\ (g/100)^{n-1}$$
$$= (A_1/365X_n)Y$$

Again the peak ratio factor, $(g/100)^{n-1}$, abbreviated as Y, depends only upon n and g and may be evaluated for selected values. Figure E-2 presents the values of this expression for n values from 20 to 30 years and for growth rates from 0 to 7 per cent per year. The use of the figure may be illustrated by estimating the peak requirement in the 30th year for a market growing at 4.4 per cent per year. The peak ratio factor from Figure E-2 is 3.5 meaning that the 30th year peak would be 3.5 times the initial peak if the load factor did not change.

The use of an equivalent constant growth rate, under circumstances where it is anticipated that the growth rate will actually decline, leads to a terminal year peak somewhat higher than would be obtained from a year to year projection. The ratio of the peak anticipated on a year to year declining growth basis to that calculated on an equivalent constant growth basis has been found to be close to 0.7. Introducing this correction,

$$P_n = (0.7A_1/365X_n)Y$$

Reserve Needed for Future Peak

Gas producing fields vary significantly in the deliverability which may be developed economically per unit of reserve. The chief factors influencing this variation are depth and cost of drilling, permeability and pay thickness, and well spacing. The gas caps of fields of the type of Leduc D-3, Bonnie Glen, and Westerose have a high gas deliverability per unit of remaining gas reserve because of the low well cost, the good permeability and pay thickness and the close spacing resulting from their primary development being for oil. At the other extreme are fields such as Pincher Creek and Jumping Pound with high well cost, low permeability and one section or greater spacing.

The Board has analyzed the characteristics of these and many other fields and finds that the remaining reserve-deliverability ratio (the inverse of the deliverability per unit of reserve) varies from somewhat below 1 Bcf per MMcfd to about 4.5 Bcf per MMcfd. This ratio, called the reserve-delivery factor, F, may be estimated closely for a single field or pool and reasonably well for an integrated group of fields. By applying the factor to P_n, the terminal year peak day requirement, the reserve needed for that future peak may be estimated as

$$FP_n = F(0.7A_1/365X_n)Y$$

Total Reserve Needed for Future Requirement

The total reserve needed for a future requirement for n years, R_n, is simply the sum of the two previously calculated reserve quantities.

$$R_n = A_1 \left(S + \frac{0.7F}{365X_n} Y \right)$$

The quantities needed for the calculation are

A_1 = the annual requirement of the first (or present) year,

n = the number of future years to be considered,

g = the effective growth rate, per cent per year,

X_n = the load factor of the n^{th} year, fraction,

F = the reserve-delivery ratio characteristic of the supply fields, Bcf per MMcfd,

and Figures E-1 and E-2 provide the values of S and Y directly.

For application to a new market area, such as Eastern Canada, the formula method should be employed only to those years beyond the initial period of market development. This means that the requirements should be forecasted on a year to year basis for a period of, say, 5 years and that the period of, say, the 6th to the 25th year could be estimated by formula.

APPLICATION OF THE METHOD TO THE PRESENT SITUATION

Future Alberta Requirements and Needed Reserves Exclusive of Peace River Area

In the application of the formula method to the computation of the reserves needed for Alberta future requirements it has been assumed that the 25th year peak and 28 years of the annual requirements would be met from established reserves, with the remaining peak and annual requirements allocated to future reserves.

The computations and results of the formula estimates of Alberta's future gas requirements and needed reserves exclusive of the Peace River area are presented in Table E-1. The estimates are sub-divided by provincial marketing areas and for annual requirements for 28 and 30 years and peak requirements for 25 and 30 years. Referring to Table E-1, column 2 indicates the annual requirements for the year 1958 and column 3 gives the effective or average growth rate assumed in the formula calculation. The growth rates of column 3 and the terminal year load factor in column 4 have been taken to lead to overall requirements consistent with those presented in Appendix C. Column 5 presents the reserve delivery ratio estimated to be characteristic of the supply fields. Columns 6 and 7 give the summation factors S for 28 years and 30 years respectively, taken from Figure E-1 for the growth rate of column 3. Columns 8 and 9 give the total of the annual requirements for future periods of 28 and 30 years respectively. Columns 10 and 11 present the peak ratio factor Y for 25 and 30 years respectively determined from Figure E-2 for the growth rate of column 3. Columns 12 and 13 show the estimated peak day requirement for the 25th and 30th year respectively. Columns 14 and 15 give the estimated reserve needed for delivery of gas at rates corresponding with the terminal year peaks of columns 12 and 13. Column 16, being the total of column 9 and column 15, indicates the total reserve needed to meet both the annual and the peak day requirements for a 30 year period. Column 17, being the total of column 8 and column 14, gives the total reserves needed to meet the annual requirements for 28 years and the peak requirements for 25 years. Column 18, being the difference between columns 16 and 17, indicates those reserves needed to meet the peak requirements for the 26th to 30th years and the annual requirements for the 29th and 30th year.

The formula calculation shows that the future annual requirements of Alberta for 30 years are some 7.6 trillion cubic feet compared with 7.7 trillion cubic feet estimated (Alberta excluding Peace River Area) in Appendix C. This agreement is not a check of one method against the other because the growth rates employed in Table E-1 were selected to give the same total. Table E-1 indicates that the total reserves needed to be retained to protect both the annual and the peak day requirements of Alberta for 30 years are 10.7 trillion cubic feet. It further demonstrates that 9.3 trillion cubic feet would have to be retained to protect the annual requirements for 28 years and the peak requirements for 25 years. The difference of some 1.4 trillion cubic feet represents the reserves required to meet the 26th to 30th year peaks and the 29th and 30th annual requirements.

Future Requirements and Needed Reserves for Present Export Commitments

The future requirements and needed reserves for present export commitments exclusive of those from the Peace River Area are listed in Table E-2. Columns 2, 3 and 4 of this tabulation give the quantities of gas authorized for export, the amount exported to December 31, 1957, and the remaining permit commitment. Column 5 gives the terminal date of the permit and column 6 the terminal peak day requirement taken as the maximum daily quantity authorized in the permit. Column 7 presents the reserve delivery ratio F estimated to be characteristic of the supply fields. Column 8, being the product of columns 6 and 7, indicates the reserve required to be in the ground as of the terminal date of the permit. Column 9, being the total of columns 4 and 8, gives the total reserves now needed to meet the export commitment. It must be recognized that of the totals shown in column 9 that the portion shown in column 8 would be available after the terminal date of the permit, although not all of it would be useable within the period from the end of the permit to the end of 1987. The Board has estimated the part of the reserves shown in column 8 useable (for annual requirements and the meeting of peaks) before the end of 1987 and has deducted it from the totals shown in column 9 to obtain the Net Needed Reserves, 1958-1987, shown in column 10. These figures indicate that a total reserve of some 5.7 trillion cubic feet is required over the period 1958 to 1987 for the protection of the existing export permits exclusive of those based on gas from the Peace River Area.

Table E-2 also presents a calculation of the reserves needed for the protection of the additional contractable Canadian requirements of Trans-Canada Pipe Lines Limited taken as 1.456 trillion cubic feet. The net needed reserves to protect this requirement are estimated at about 1.7 trillion cubic feet.

Recapitulation and Evaluation of Surplus Established Gas

The results from Tables E-1 and E-2 together with the estimate of established reserves within economic reach but exclusive of the Peace River Area permit an immediate determination of the surplus in established reserves.

Established Reserves within Economic Reach Exclusive of Peace River Area		20.8 Tcf
Required for 25 Year Peak and 28 Year Annual in Alberta	9.3 Tcf	
Required for Existing Permits Exclusive of Those from the Peace River Area	5.7 Tcf	
Required for Contractable Other Future Canadian Requirements of Trans-Canada Pipe Lines Limited	1.7 Tcf	
Subtotal	16.7 Tcf	
Surplus to Requirements of Alberta, Existing Export Commitments and Contractable Other Canadian Requirements	4.1 Tcf	
Total		20.8 Tcf

The 4.1 Tcf surplus calculated this way is in agreement with the 4.1 Tcf surplus resulting from the detailed deliverability analysis and appearing in Table D-9.

Illustrative "Allocation" of Fields to Markets and to Surplus

Table E-3 presents an illustrative allocation of reserves totalling the required 16.7 Tcf to Alberta requirements, existing permits and the contractable Canadian requirements of Trans-Canada Pipe Lines Limited. This table has been prepared independently of the deliverability schedules of Appendix D but for the convenience the same composites of fields have been employed. Except for existing arrangements, the reserve "allocation" has been based on the Board's judgment of the suitability of the reserve for the market.

Columns 4, 5, 7 and 8 list reserves for the indicated marketing areas, each totalling the needed reserves shown in column 17 of Table E-1 -- i.e. to give protection for the 25th year peak and 28 years of annual requirements. To be consistent with Appendix D, column 6 shows the reserves needed for the full 30 year annual and peak requirements of the Medicine Hat Area as determined in column 16 of Table E-1.

In the case of the Northwestern Utilities, Limited Area, the full 25 year peak and 28 year annual protection could not be obtained from geographically suitable fields and a small deficit (222 billion cubic feet or 5 per cent of the total needed reserves) remains. This deficit which is not considered very significant, has arbitrarily been allocated to the Edmonton Deferred Gas Composite.

Fields or reserves not needed to protect the above requirements and therefore surplus are listed in column 14 of this Table. This listing is substantially the same as that given in column 2 of Table D-9.

The "formula" calculation has therefore, in a much shorter way, led directly to the same answer obtained from detailed deliverability analysis. The surplus gas is that of column 14 of Table E-3 or column 2 of Table D-9 and is considered in more detail in Tables D-9, D-10 and D-11 of Appendix D.

Recapitulation and Evaluation of Surplus Future Gas

A comparison of those requirements to be met from the future reserves with the estimate of future reserves may also be made. The Alberta requirements from future reserves are the some 1.4 Tcf calculated in Table E-1. The long term additional future Canadian requirements of Trans-Canada Pipe Lines Limited may be estimated by a calculation of the total future Canadian requirements of Trans-Canada (including the requirements now under permit and those estimated to be contractable) and then subtracting the requirements under permit and contractable. The total future estimate, assuming a 5 per cent per year growth from an annual of 254 Bcf in 1962, for the period 1958-1987, shows annual requirements of 9.5 Tcf and needed reserves totalling 12.4 Tcf. Subtracting the 5.15 Tcf and the 1.69 Tcf from Table E-2 results in a needed reserve to protect the additional long term future requirements of some 5.6 Tcf.

The recapitulation may now be made as follows:

Estimated Future Reserves April 1, 1958 to December 31, 1987		51 Tcf
Required for 26-30th Year Peaks and 29, 30th Year Annual in Alberta	1.4 Tcf	
Required for Long Terms Future Canadian Requirements of Trans-Canada Pipe Lines Limited	5.6 Tcf	
Subtotal	7.0 Tcf	
Surplus in Future Reserves	44 Tcf	
Total		51 Tcf

From this comparison and the very large surplus in future reserves it is clear that more than adequate protection is available for the future requirements allocated to it.

TABLE E - 1
OIL AND GAS CONSERVATION BOARD

FUTURE ALBERTA GAS REQUIREMENTS AND REQUIRED RESERVES EXCLUSIVE OF THE PEACE RIVER AREA (1000 BTU BASIS)

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
AREA	1958 ANNUAL REQUIREMENTS A_1	AVERAGE GROWTH RATE g	TERMINAL YEAR LOAD FACTOR X_n	RESERVE-DELIVERY FACTOR F	SUMMATION FACTOR S		FUTURE REQUIRE-MENTS A_1S		PEAK RATIO FACTOR Y		TERMINAL YEAR PEAK P_n		RESERVES REQUIRED FOR TERMINAL YEAR PEAK FF_n		TOTAL REQUIRED RESERVES	RESERVES REQUIRED FOR 25TH YEAR PEAK AND 28TH YEAR ANNUAL	RESERVES REQUIRED TO MEET PEAKS FOR THE 26TH TO 30TH YEARS AND ANNUAL REQUIREMENTS FOR THE 29TH AND 30TH YEAR
	BCF	PER CENT PER YEAR		BCF PER MMCFD	28 YEARS	30 YEARS	28 YEARS BCF	30 YEARS BCF	25 YEARS	30 YEARS	25 YEARS MMCFD	30 YEARS MMCFD	25 YEARS BCF	30 YEARS BCF	30 YEARS BCF	BCF	BCF
CANADIAN WESTERN NATURAL GAS COMPANY LIMITED	40.0	4.2	45	3.0	51.5	58.0	2060	2320	2.69	3.28	458	560	1373	1680	4000	3433	567
NORTHWESTERN UTILITIES LIMITED	66.1(2)	4.3	52	0.9	52.3	59.1	3460	3900	2.75	3.37	670	823	604	740	4640	4064	576
MEDICINE HAT	12.5	2.6	70	4.5	40.5	44.6	506	558	1.85	2.10	63	72	285	324	882	791	91
WABAMUN-HINTON	11.9 (9.6)(1)	2.0	76	2.0	25.8(4)	33.6(3)	308(5)	382(5)	1.50(4)	1.65(3)	36	40	72	80	462	380	82
REMAINDER OF THE PROVINCE	9.0(2)	3.5	40	2.0	46.4	51.6	418	464	2.28	2.70	98	116	196	233	697	614	83
PROVINCIAL TOTAL (EXCLUSIVE OF PEACE RIVER)	139.5(2)	3.8	49	1.9	48.7	55.1	6752	7624	2.45	2.95	1325	1611	2530	3057	10681	9282	1399

(1) UNIFORM GROWTH RATE ASSUMED TO START IN 1962 @ 9.6 BCF.

(2) THESE FIGURES ARE NOT CONSISTENT WITH THOSE USED IN THE TABLES OF APPENDIX C.

(3) 26TH YEAR FACTOR.

(4) 21ST YEAR FACTOR.

(5) FIGURE REPRESENTS 60 BCF PLUS PROJECTION FROM 5TH TO 30TH YEAR.

TABLE E - 2

OIL AND GAS CONSERVATION BOARD

FUTURE REQUIREMENTS AND REQUIRED RESERVES FOR PRESENT EXPORT COMMITMENTS* AND CONTRACTABLE CANADIAN REQUIREMENTS OF TRANS-CANADA PIPE LINES LIMITED (1000 BTU BASIS)

1 EXPORTING FIRM	2 AUTHORIZED AMOUNT OF EXPORT BCF	3 AMOUNT EXPORTED TO DECEMBER 31, 1957 BCF	4 REMAINING PERMIT COMMITMENT BCF	5 TERMINAL DATE OF PERMIT	6 TERMINAL PEAK DAY P_n MMCFD	7 RESERVE-DELIVERY RATIO F BCF PER MMCFD	8 RESERVES REQUIRED FOR TERMINAL PEAK FP_n BCF	9 RESERVES NOW REQUIRED FOR PROTECTION TO TERMINAL DATES OF PERMITS BCF	10 NET RESERVES REQUIRED OVER PERIOD 1958 - 1987 BCF
Canadian Montana Pipe Line Company	314.9	57.9	257.0	May 13, 1974	-	-	Nil	257.0	257
Saskatchewan Power Corporation	212.0	-	212.0	July 1. 1978	79.0	4.5	355.0	567.0	270 (say)
Trans-Canada Pipe Lines Limited (Existing Permit)	4480.0	2.8	4477.2	May 13, 1981	639.0	2.5	1600.0	6077.2	5150 (say)
Sub Total	5006.9	60.7	4946.2		718.0		1955.0	6901.2	5677
Contractable Future Trans-Canada Canadian Requirements	1456.0	-	1456.0	December 31, 1980	227.0	2.0	554.0	2010.0	1690 (say)
TOTAL	6462.9	60.7	6402.2		945.0		2509.0	8911.2	7367

* Exclusive of those from the Peace River Area.

TABLE E - 3

OIL AND GAS CONSERVATION BOARD

ILLUSTRATIVE ALLOCATION OF ESTABLISHED RESERVES NECESSARY TO MEET FUTURE REQUIREMENTS OF ALBERTA, PRESENT EXPORT COMMITMENTS AND CONTRACTABLE CANADIAN REQUIREMENTS OF TRANS-CANADA PIPE LINES LIMITED

1	2	3	4	5	6	7	8	9	10	11	12	13	14
FIELD OR POOL	REFERENCE	REMAINING DISPOSABLE RESERVES (1000 BTU BASIS) BCF	CANADIAN WESTERN NATURAL GAS COMPANY LIMITED AREA BCF	NORTHWESTERN UTILITIES LIMITED AREA BCF	MEDICINE HAT BCF	WABAMUN-HINTON BCF	REMAINDER* OF ALBERTA BCF	ALBERTA* TOTAL BCF	CANADIAN MONTANA PIPE LINE COMPANY BCF	SASKATCHEWAN POWER CORPORATION BCF	TRANS-CANADA PIPE LINES LIMITED EXISTING PERMIT BCF	CONTRACTABLE FUTURE TRANS-CANADA CANADIAN REQUIREMENTS BCF	SURPLUS BCF
Stettler Composite	Table D-12	210	100	110				210					
Jumping Pound		525	525					525					
Okotoks		132	132					132					
Foremost-Bow Island		37	37					37					
Turner Valley		379	379					379					
Carbon		246	246					246					
Calgary		1039 }											
Sarcee		103 }	2014					} 2014					
Harmattan-Elkton	Table D-12	1241 }											369
Edmonton Oilfield Composite	Table D-1	1328		1328				1328					
Edmonton Dry Gas Composite	Table D-12	1404		1404				1404					
Lloydminster		10		10				10					
Edmonton Deferred Gas Composite	Table D-12	990		1212				1212					(222)
Etzikom		109			109			109					
Bow Island & Ellis - Medicine Hat		19			19			19					
Medicine Hat Sand - Medicine Hat		1283			754			754		270		259	
Alexander Composite	Table D-12	68				68		68					
Pine Creek Composite	Table D-12	344				312		312					32
Pakowki Composite	Table E-4	257							257				
Trans-Canada Permit Fields	Table D-6	5890									5150	740	
Trans-Canada Dry Gas Composite	Table D-12	434										434	
Westerose South		1178										257	921
Crossfield		189											189
Garrington		40											40
Innisfail		80											80
Minnehik-Buck Lake		291											291
Panther River		116											116
Parkland		20											20
Savanna Creek		539											539
Waterton		742											742
Wimborne		169											169
Local Utilities	Table E-4	150					150	150					
Deferred Gas	Table E-4	532											532
Other Small Fields Not Allocated	Table E-4	430 }											
Economic Reserves Less Than 10 Bcf		230 }					} 474	} 474					} 186
Needed Reserves		20754	3433	4064	882	380	624	9383	257	270	5150	1690	4004

* Excluding the Peace River Area

TABLE E - 4

OIL AND GAS CONSERVATION BOARD

DETAILS OF CERTAIN COMPOSITES OF TABLE E - 3

NAME OF COMPOSITE	NAME OF FIELD
Pakowki Lake	Black Butte
	Comrey
	Manyberries
	Pendant d'Oreille
	Smith Coulee
Local Utilities	Athabasca
	Athabasca East
	Bonnyville
	Brooks North-East
	Brooks-Tilley
	Cold Lake
	Dowling Lake
	Duvernay
	Elk Point
	Hairy Hill
	Leahurst
	Lindbergh
	Oberlin
	Redwater (Viking Zone)
	Rosedale
	St. Paul
	Suffield
	Watts
Deferred Gas	Bonnie Glen Associated
	Golden Spike
Other Small Fields Not Allocated	Antelope
	Bellshill Lake
	Calgary (Basal Blairmore)
	Castor
	Connorsville
	Control
	Duhamel
	Enchant
	Ghost Pine
	Grassy Island Lake
	Hilda
	Joffre (Nisku Zone)
	Malmo
	Mazeppa
	New Norway
	Pembina (Belly River, Basal Blairmore and Rundle)
	Provost (Blairmore Zone)
	Rolling Hills
	Three Hills Creek (Viking and Blairmore)
	Turin
	West Drumheller

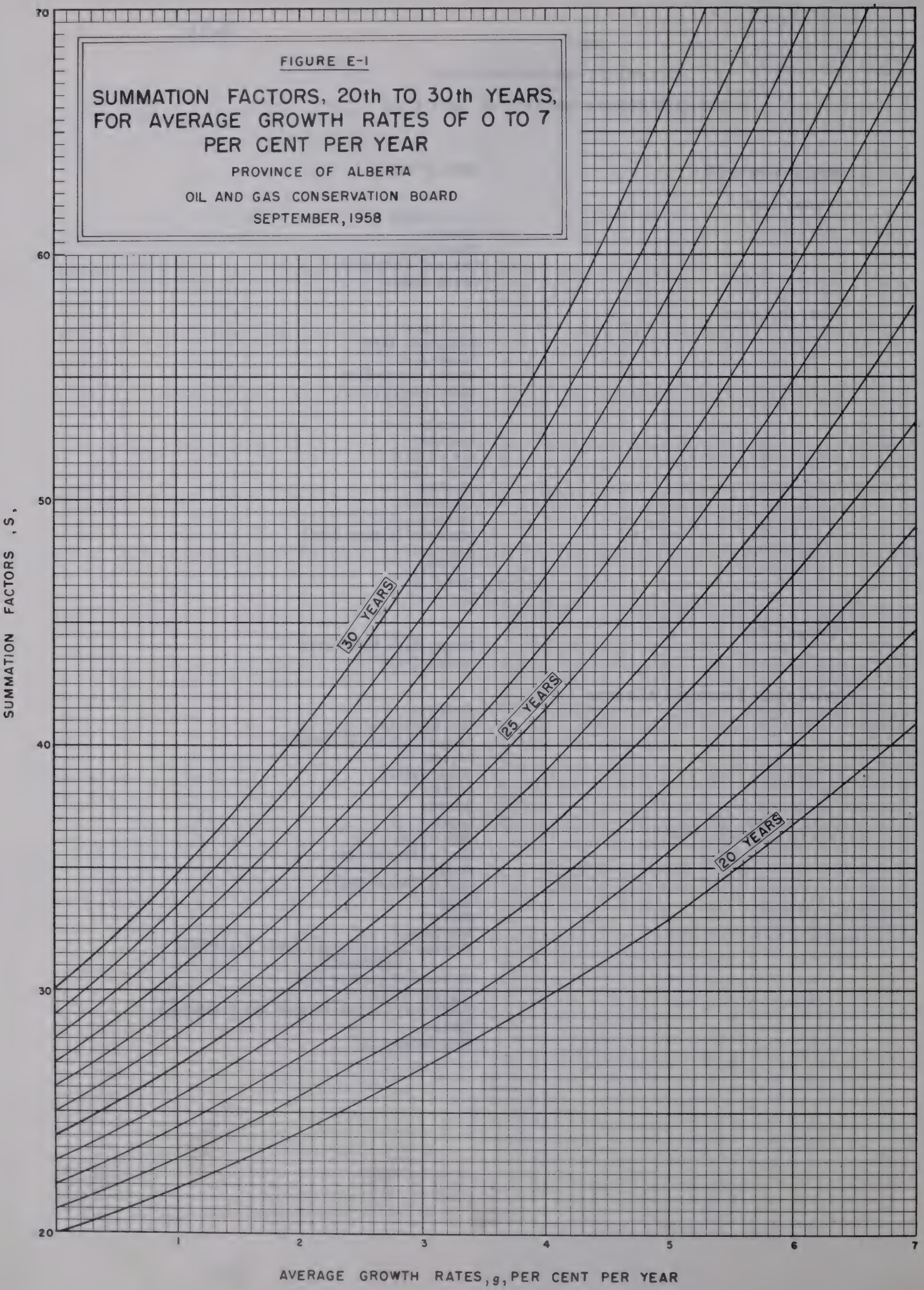


FIGURE E-1

SUMMATION FACTORS, 20th TO 30th YEARS, FOR AVERAGE GROWTH RATES OF 0 TO 7 PER CENT PER YEAR

PROVINCE OF ALBERTA

OIL AND GAS CONSERVATION BOARD

SEPTEMBER, 1958

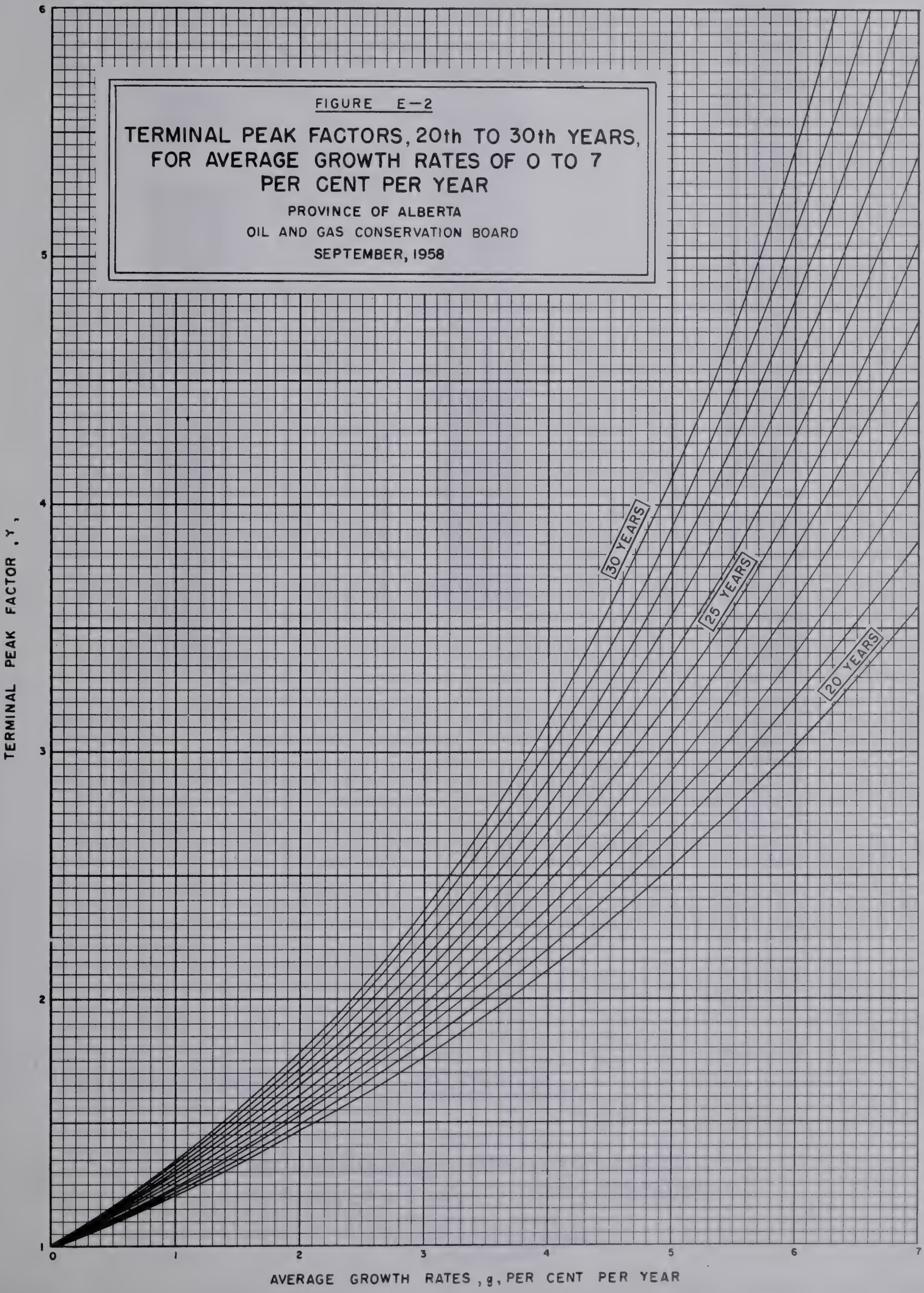


FIGURE E—2

TERMINAL PEAK FACTORS, 20th TO 30th YEARS, FOR AVERAGE GROWTH RATES OF 0 TO 7 PER CENT PER YEAR

PROVINCE OF ALBERTA
OIL AND GAS CONSERVATION BOARD
SEPTEMBER, 1958

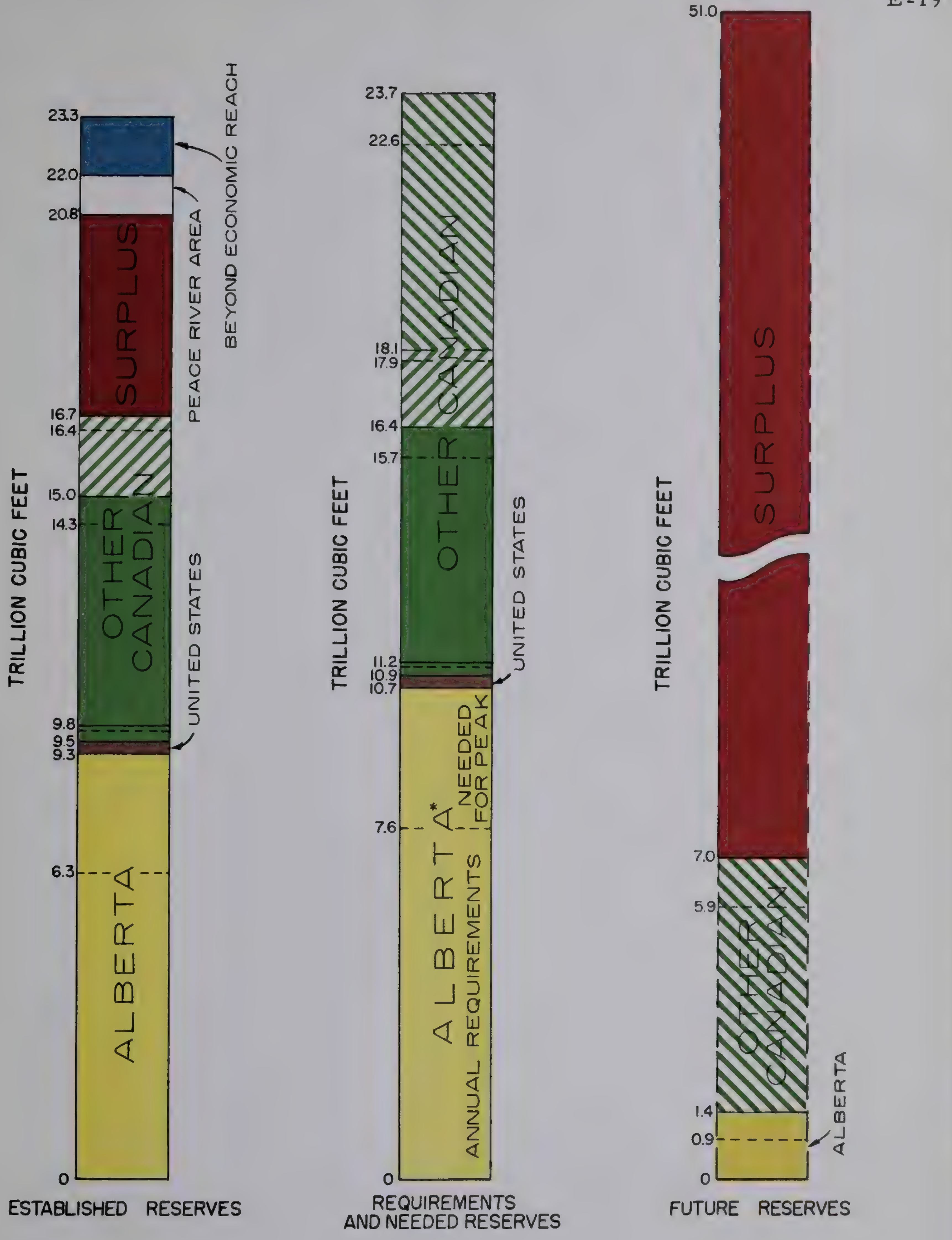


FIGURE E-3

SCHEMATIC REPRESENTATION OF DISPOSITION OF ESTABLISHED AND FUTURE RESERVES

PROVINCE OF ALBERTA
OIL AND GAS CONSERVATION BOARD
SEPTEMBER 1958

*EXCLUDES PEACE RIVER AREA

[illegible]